Northwest Energy Company

Annual Report for 1981

AR18

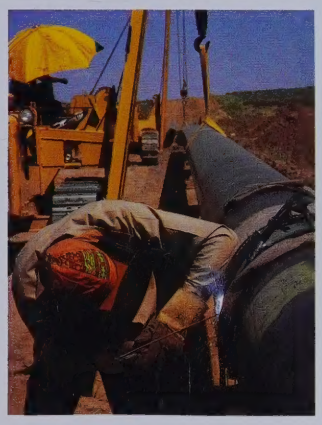
The Company

Northwest Energy Company, headquartered in Salt Lake City, Utah, is primarily involved in finding, developing and transporting energy resources. It is made up of more than 2,000 industry professionals dedicated to helping the nation meet its growing demands for energy.

A core sample from an oil discovery and a surveying compass on a computerized seismograph represent some of the geological and geophysical tools used in finding oil and gas.

Our Business

Pipeline Operations



The Company's largest subsidiary is Northwest Pipeline Corporation, which owns and operates a 6,000-mile transmission and gathering system which supplies natural gas to customers in seven Pacific Northwest and Intermountain states.

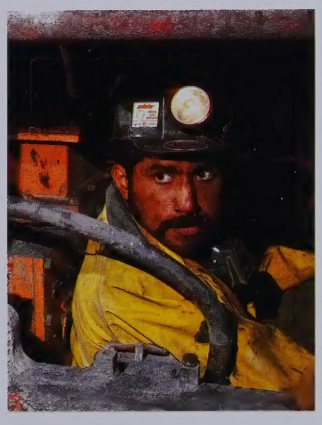
Exploration and Production

Exploration and production activities are carried out primarily by Northwest Exploration Company, which drills for oil and gas throughout the western United States and now has nearly a million net acres under oil and gas leaseholds.

Alaskan Pipeline Project

Another subsidiary, Northwest Alaskan Pipeline Company, is operator for the partnership which will build the Alaskan segment of the Alaska Natural Gas Transportation System, a 4,800-mile pipeline designed to transport gas from the North Slope of Alaska to the lower 48 states.

Coal Operations



Coal operations include an underground mine in western Colorado owned and operated by a wholly owned subsidiary of Northwest Coal Corporation. The mine supplies high-BTU, low-sulfur, bituminous coal to a midwestern power-generating facility and foreign markets.

Highlights

(Dollars in Millions, Where Applicable)

Northwest Energy Company and Subsidiaries

Year Ended December 31,	1981	1980	Percent Increase
Operating revenues	**$1,398.8**	$1,323.4	6%
Net income	**$ 70.1**	$ 54.1	30
Less—Preference stock dividend requirement	**6.3**	2.8	125
Net income applicable to common stock	**$ 63.8**	$ 51.3	24
Income per share applicable to common stock and common stock equivalents:			
Primary	**$ 3.83**	$ 3.23	19
Fully diluted	**$ 3.64**	$ 3.16	15
Weighted average number of common shares and common stock equivalents outstanding, in thousands:			
Primary	**16,882**	15,876	6
Fully diluted	**19,510**	17,099	14
Common stock data:			
Book value per share (end of year)	**$ 21.68**	$ 18.78	15
Dividends declared per share	**$ 1.15**	$ .95	21
Percentage of dividends to net income	**30%**	29%	3
Capital expenditures	**$ 269.0**	$ 208.0	29
Total assets (end of year)	**$1,538.0**	$1,073.6	43

In the fall of 1981, Northwest Pipeline completed the 351-mile expansion of its main transmission line in Oregon and Idaho. At right, an engineer inspects the project during construction.

To Our Stockholders:

The year 1981 was filled with challenges and opportunities. We are extremely gratified with the exceptional progress of Northwest Energy Company during the year. Earnings reached record levels and we had several other notable achievements:

—Northwest Pipeline Corporation, our principal subsidiary, completed a major expansion of its main transmission line in Oregon and Idaho, connected a record number of new natural gas wells, and constructed a record number of gathering system additions. In addition, Northwest Pipeline signed a gas sales agreement with Texas Eastern Transmission Corporation and its subsidiary, Transwestern Pipeline Company, which will provide an investment opportunity of approximately $272 million in new pipeline facilities during 1982 and 1983 and will enable gas to be delivered through interconnecting pipelines to southern California and the East Coast.

—Northwest Exploration continued to make impressive progress with a fivefold increase in proved net oil reserves and a significant increase both in gas reserves and gas production. We began exploratory operations in 1974 and have just begun to capitalize on the foundation laid during the formative years.

—Another highlight of 1981 was passage by the Congress in December of legislation to aid private financing of the Alaska Natural Gas Transportation System. With this approval, we're eagerly moving forward to develop a private financing plan so that the project can be completed in a timely fashion.

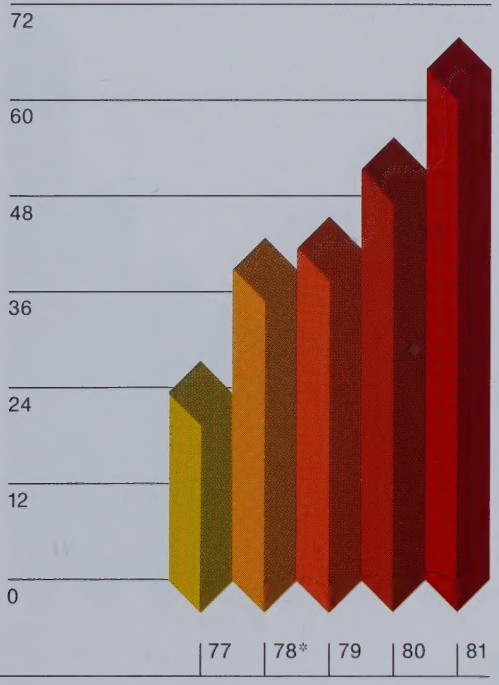
Gathering system expansion

In 1980, Northwest Pipeline connected a record 317 new gas wells, and at that time we predicted we would connect approximately 350 in 1981. By year-end, however, we had connected 524 new wells to our existing pipeline system. The new gathering systems which must be constructed to connect these wells give us exposure to significant discoveries being made in the Rocky Mountain states of Colorado, Wyoming, Utah and New Mexico in areas adjacent to our pipeline system. During 1981, gathering system additions totaled 483 miles. The increasing drilling activity in the Rockies and our pipeline's strategic location give us confidence that we'll be connecting 500 wells or more each year into the foreseeable future and making substantial new additions to Northwest Pipeline's gathering system.

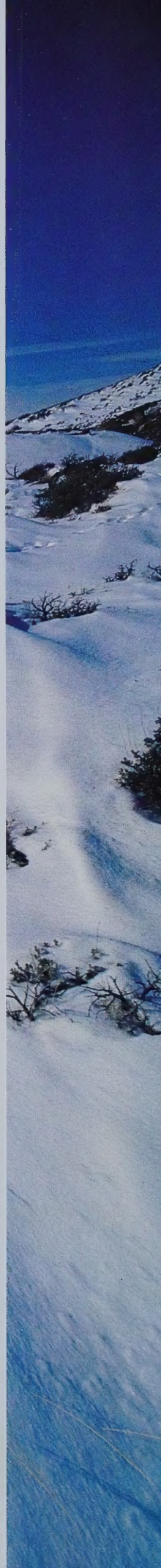
At the end of 1981, Northwest Pipeline's reserve life index was 21.6 years, the highest of any major gas transmission company in the United States.

Net Income Applicable to Common Stock

$Millions



*Including extraordinary items of $15.4 million.



As part of the early construction phase of the Alaskan project, segments of the Western Leg were completed in both the U.S. and Canada during 1981. Canadian natural gas began flowing in October through these segments to Stanfield, Oregon, where the gas was delivered to Northwest Pipeline, which completed a 351-mile expansion of its main transmission line in Oregon and Idaho to transport the Canadian volumes for ultimate use in southern California. Northwest Pipeline invested some $127 million in the expansion project, which will provide a significant earnings boost during 1982 and thereafter.

The above system expansions were in large part responsible for Northwest Pipeline filing for increased rates amounting to approximately $115.7 million annually, effective October 1, 1981. The higher rates are being collected subject to refund and are designed to recover, in part, increased debt costs and provide a higher rate of return on common equity. A further increase in rates will be sought in 1982.

Future pipeline expansion

Westcoast Transmission Company Limited of Vancouver, British Columbia has agreed to increase natural gas deliveries to Northwest Pipeline under the Sumas contract from 809 million to 869 million cubic feet per day, when the sale to Texas Eastern commences.

The new agreement also provides that Northwest Pipeline and Westcoast will immediately enter into negotiations for a ten-year extension of the present contract, which expires October 31, 1989. The companies are currently negotiating the contract extension and are expected to file with appropriate regulatory authorities in the U.S. and Canada later this year.

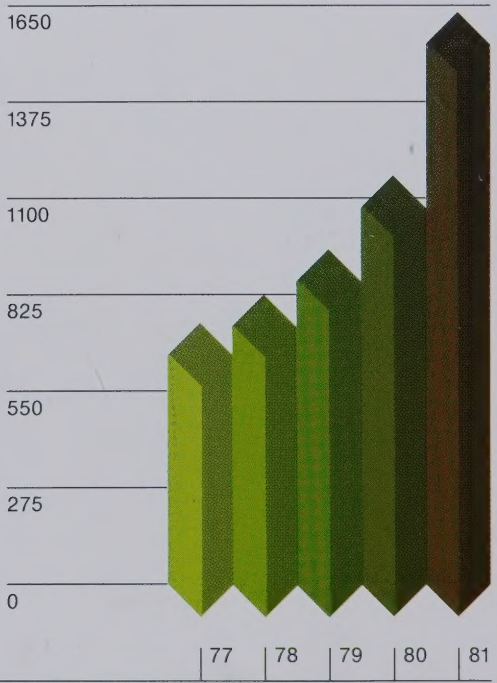
Over the next five years, expansion on our existing pipeline system alone will require an estimated investment of at least $1.2 billion in new facilities. This investment will permit the Company to continue to move into promising areas as quickly as possible and will permit us to serve new market areas by providing transportation services for other companies.

Reduced impact of decontrol

There has been much discussion in both the government and industry about accelerated decontrol of natural gas. If Congress approves an accelerated decontrol measure, we believe that the impact on Northwest Pipeline and its customers will not be nearly as great as the impact on those companies relying exclusively on domestic supplies. Northwest Pipeline has always had a large share of Canadian natural gas in its overall supply mix. Since 1974, the price of Canadian gas has risen rapidly to its present level of $4.94 per million BTUs. As a result, Northwest Pipeline's markets have already absorbed a big part of the probable price increases which might be expected under accelerated decontrol of U.S. gas supplies.

Total Assets

$Millions



The higher-cost Canadian gas has placed gas distributors in the Pacific Northwest at a competitive disadvantage with certain alternate fuels prevalent in our market area. As a result, Northwest Pipeline's sales volumes declined nearly 25% two years ago. Since then, both the cost of natural gas and the markets have stabilized and there are indications that the competitive posture of natural gas is improving in the Pacific Northwest and may continue to improve even with decontrol.

Exploration and production expands

During 1981, Northwest Exploration drilled or participated in drilling four oil discoveries. This year Northwest Exploration plans to spend more than $43 million to develop the acreage on which discoveries were made and to further assess the nearly one million net acres under oil and gas leaseholds. In addition, it is expanding its lease acquisition program. Subsidiaries of Northwest Energy have also acquired a one-half interest in a producing oil property in Hockley County, Texas and are participating in an exploratory program in Argentina.

Each year, the Company's exploration and production activities have added increasing amounts to consolidated net income. We expect this trend to continue and significantly accelerate as these operations expand.

With respect to the Alaska Highway Pipeline Project, we took a giant stride toward financing the Alaskan segment when Congress passed legislation in December waiving provisions of law which had rendered private financing virtually impossible. The new federal legislation provides important assurances to lenders and allows equity participation by the North Slope producing companies. As a result, we are confident that private financing can be achieved and that regulatory approvals can be obtained in a timely manner to permit construction to go forward.

Approximately 1,500 miles, or 30% of the project's total pipeline mileage, will be completed this year when the initial phase of the Northern Border segment (U.S. Eastern Leg) and the Canadian Eastern Leg become operational.

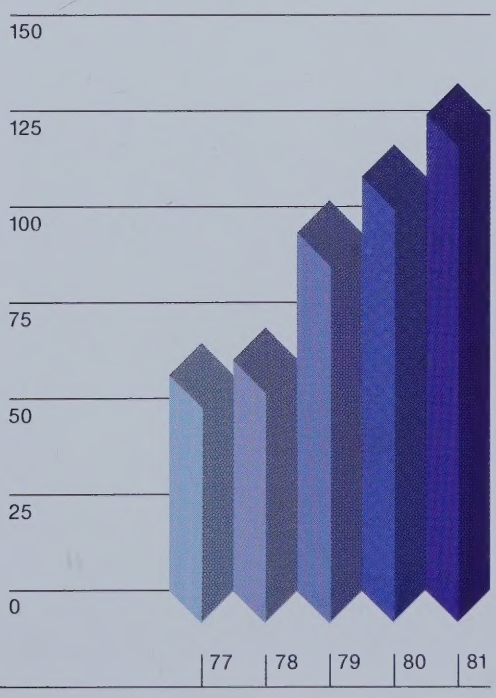
The Alaskan project will give our nation access to the enormous gas reserves contained in the largest oil and gas reservoir ever found in North America. Natural gas from Prudhoe Bay could cut our imports of oil by at least 400,000 barrels daily and will significantly reduce foreign payments each year during the 25- to 30-year life of the project.

Substantial earnings boost

Northwest Energy's investments in its gas transmission activities, in its exploration and production operations and in the Alaskan and Northern Border segments will provide a substantial increase in earnings during the next several years. These

Funds Provided from Operations

$Millions



investments will also provide substantial cash flow as new facilities are placed in operation.

We expect our total consolidated capital expenditures over the next five years to reach $2.1 billion as a result of our activities in the energy field. A large part of this required investment will be provided from internally generated funds which have more than doubled in the past five years.

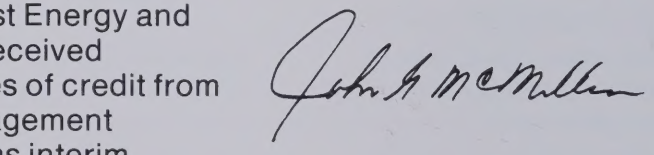
However, Northwest Energy's capital expenditure program will also require substantial external financing. With respect to these financings, it is our intent to minimize the dilution impact on the Company's stockholders to the fullest extent possible. At the same time, we intend to maintain a responsible and flexible capital structure that assures our access to capital markets at all times. In July, a subsidiary of the Company issued $40 million of 9% convertible subordinated debentures due 1996. The debentures are convertible into common stock or into 16½% subordinated debentures. Northwest Pipeline issued $100 million of 16¾% debentures in May 1981 and recently converted a $90 million revolving credit facility to a six-year term-loan. In addition, Northwest Energy and Northwest Pipeline have received approval of committed lines of credit from various banks which management believes will be adequate as interim financing prior to entering the long-term securities markets. The Company anticipates that it will issue new debt and equity securities during 1982 amounting to approximately $140 million.

Dividends on common stock

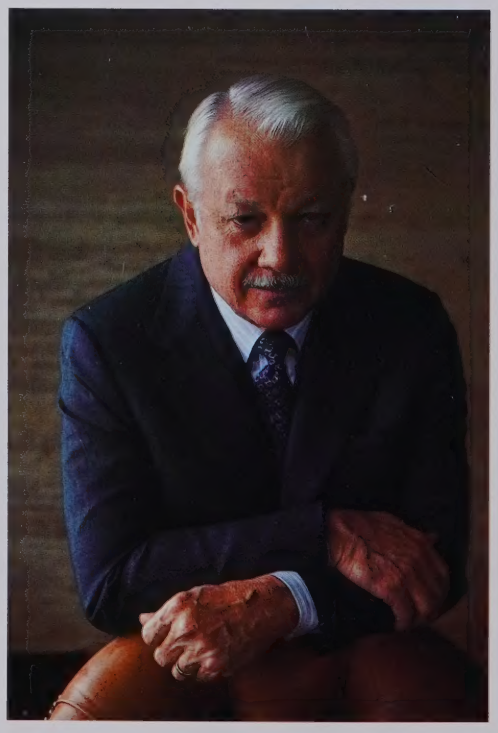
The Board of Directors seeks to balance investor requirements and expectations with the Company's need to retain substantial capital for its growth needs. The Board reviews the dividend payment regularly and has increased the dividend eight times in the past seven years. Our dividend on common stock (adjusted for stock distributions) has increased from approximately 27 cents per common share in 1974 to the present annual rate of $1.20 per share, a 344% increase.

America's energy requirements have never been greater. Our challenge—to help meet those needs—provides opportunities for unparalleled growth. We have every confidence that we can make the most of the opportunities posed by the energy challenges of the 1980s.

Once again, let me express my thanks to you for your generous support. As we look to the future, we believe we will continue to merit your trust and confidence.



John G. McMillian
Chairman and Chief
Executive Officer



Pipeline Operations

The Company's pipeline subsidiary, Northwest Pipeline Corporation, completed a 351-mile expansion of its main transmission line in the fall of 1981 to permit delivery of natural gas from Canada through southern portions of the Alaska Natural Gas Transportation System (ANGTS). The construction on the Northwest Pipeline system involved the segment from Stanfield, Oregon to Burley, Idaho and was completed on schedule and under budget.

The expansion allows Northwest Pipeline to receive additional Canadian gas at Stanfield from Pacific Gas Transmission Company, which added 160 miles of 42-inch diameter pipeline to its existing transmission system between the United States-Canadian border near Kingsgate, British Columbia and Stanfield as part of the Western Leg segment of the ANGTS. Foothills Pipe Lines Ltd. also added 132 miles of 36-inch diameter pipeline to its transmission system in Canada as part of the project. The expanded systems both in Canada and the U.S. will accommodate additional volumes of up to 300 million cubic feet of natural gas per day, and these facilities allow Canadian gas to be delivered through El Paso Natural Gas Company to Pacific Interstate Transmission Company in southern California.

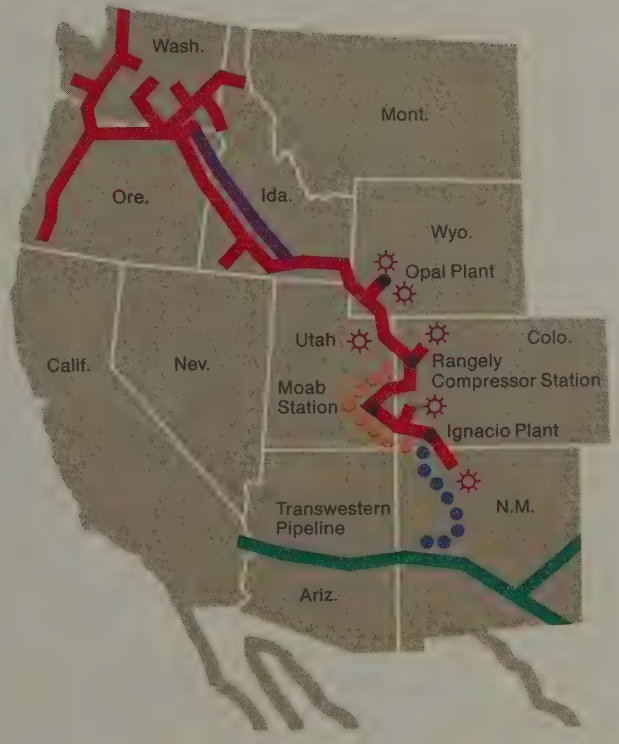
The total cost of the Northwest Pipeline expansion was $178 million, excluding the allowance for equity funds used during construction. Northwest Pipeline's portion of the cost was $127 million. The remainder was financed by the purchaser of the gas, Pacific Interstate Transmission Company of Los Angeles, which owns 30% of the facilities. Pacific Interstate has contracted to purchase an average of 240 million cubic feet per day of Canadian gas.

New facilities completed

The company set records in 1981 by connecting a total of 524 new wells and adding 483 miles of gathering system lines. This mileage is more than 16% of all gathering system pipelines constructed in the United States in 1981. The 1981 records compare with 317 wells connected in 1980 and 296 miles of new gathering system pipelines. On February 1, 1974, when Northwest Pipeline began operations, the company had 1,163 miles of gathering system pipelines. At the end of 1981, that total had reached 2,732 miles.

Of the wells Northwest Pipeline connected in 1981, 238 are in the San Juan Basin in northwestern New Mexico and southwestern Colorado, 197 are in western Colorado and eastern Utah in the Piceance and Uinta Basins, and 89 are in southwestern Wyoming in the Big Piney Field or other areas of the Green River

Workers string pipe along trench in the San Juan Basin, left. Map indicates the 351-mile expansion completed on the Northwest Pipeline system in 1981, the expansion proposed for 1982-83 and the new Continental Divide Pipeline.



Existing Northwest Pipeline System

Pipeline Expansion Completed in 1981

Proposed Northwest Pipeline Expansion

Proposed Continental Divide Pipeline System

Gas Producing Areas

Basin. Most of the sedimentary basins near the Northwest Pipeline system are expected to experience accelerated drilling activity in the years ahead. Typical wells in these areas are of low deliverability, but have productive lives of 20 to 40 years or more and provide an exceptional long-term domestic source of natural gas.

A $34 million pressure reduction project started by Northwest Pipeline a year ago in the San Juan Basin was completed in the fall of 1981 and has resulted in substantially increased deliverability. The project was designed to reduce field pressure and increase gas flow to meet requirements of gas purchase contracts.

Storage enhances deliverability

Gas storage is also important to Northwest Pipeline's deliverability. Underground storage is available at Clay Basin in Utah (20 billion cubic feet seasonally) and Jackson Prairie Storage Field in Washington (12.8 billion cubic feet). In times of peak demand, participating customers may request that gas be vaporized and delivered from Northwest Pipeline's liquefied natural gas (LNG) plant at Plymouth, Washington (2.4 billion cubic feet).

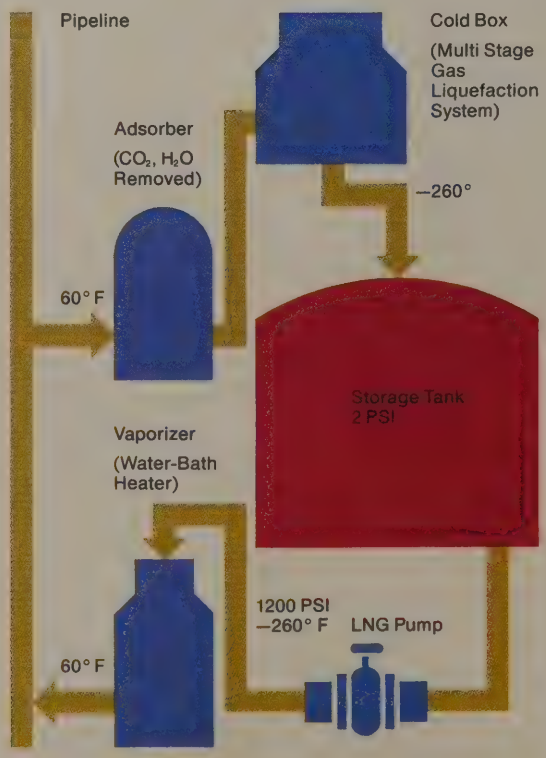
Certificated withdrawal capacity at Clay Basin is 150 million cubic feet daily and at Jackson Prairie it is 325 million cubic feet daily. Up to 300 million cubic feet of gas may be vaporized and withdrawn daily from the LNG facility. The value of gas in underground storage amounted to approximately $154 million as of December 31, 1981 and is included in Northwest Pipeline's rate base.

Northwest Pipeline has signed contracts to transport gas supplies for several other major gas transmission companies. These contracts represent reserves in excess of 1 trillion cubic feet. Volumes for transport are expected to increase significantly as development continues in the sedimentary basins and Overthrust Belt in areas near Northwest Pipeline's transmission system.

Sales to Northwest Pipeline's distribution customers in the Pacific Northwest have been hindered as a result of competition over the past few years from low-priced residual fuel oil. This situation has stabilized, however, and one effect of the lower sales volumes has been that the amount of high-cost Canadian natural gas in the overall supply mix has fallen, tending to reduce the average purchase price of natural gas to Northwest Pipeline customers. While gas sales have fallen over the past few years, these lower sales volumes have been reflected in Northwest Pipeline's unit sales rates, thereby assuring recovery of the full cost of service.

Gas supply strengthened

During 1981, Northwest Pipeline added 568 billion cubic feet of new natural gas reserves. Northwest Pipeline's proved natural gas reserves totaled 7.2 trillion cubic feet at the end of 1981, a reserve to production ratio of 21.6 years, the highest of



Northwest Pipeline's LNG facility takes gas from the main transmission line and removes water and carbon dioxide before liquefying it for storage. The gas can be pumped out of storage and vaporized as needed.

any major gas transmission company in the United States.

Canadian gas makes up about 50% of Northwest Pipeline's total requirements, with major U.S. supplies coming from the San Juan Basin (24%), the Big Piney Field of Wyoming (16%) and various other Rocky Mountain fields (10%).

With respect to Canadian supplies, Westcoast Transmission Company Limited of British Columbia has agreed to increase deliveries of gas to Northwest Pipeline at the Sumas, Washington import point from 809 million to 869 million cubic feet. The increased sale is contingent on Northwest Pipeline commencing a firm sale of up to 300 million cubic feet of natural gas daily to Texas Eastern Transmission Corporation and its subsidiary, Transwestern Pipeline Company.

Provisions of the contract negotiated with Westcoast also include a minimum purchase obligation by Northwest Pipeline of approximately 192 billion cubic feet of gas per year, equivalent to 65% of Westcoast's annual authorized exports of 295 billion cubic feet yearly. The minimum purchase obligation is contingent upon FERC approval of the sale and the commencement of gas deliveries to Texas Eastern/Transwestern.

Terms of the new contract also provide that Northwest Pipeline and Westcoast enter into negotiations to extend the present export contract, which expires October 31, 1989, for an additional ten years. The companies are currently negotiating the contract extension and are expected to request approval from appropriate regulatory authorities in the U.S. and Canada later this year.

Northwest Pipeline has natural gas processing plants at Opal, Wyoming and Ignacio, Colorado. These plants remove natural gas liquids—primarily propane, butane and natural gasoline—from the natural gas before it enters the main transmission line. In 1981, recovery of natural gas liquids at these two plants amounted to 96.4 millon gallons. Improvements are being studied for the Opal plant which would permit processing of higher gas volumes and recovery of additional liquid products.

Liquids opportunities broadened

Northwest Energy has established a separate nonregulated subsidiary, NGL Production Company, to invest in natural gas liquid processing plants located on gathering systems in the Rockies. NGL Production now has interests in four such plants, including the North Douglas Creek plant in western Colorado's Piceance Basin south of Rangely. The new plant, constructed at a cost of $1.9 million, is designed to extract approximately 7.3 million gallons of liquids per year from a raw gas volume of up to 20 million cubic feet daily. The North Douglas Creek plant is the first such facility operated by NGL Production. Two additional processing plants are proposed for construction during 1982.

Northwest has underground storage available in Utah and in Washington. Gas is compressed into the storage zone through injection wells and taken out through withdrawal wells. Stored gas improves Northwest Pipeline's deliverability.

A subsidiary of the Company has invested in a partnership which has been established primarily to market and trade in natural gas liquids extracted from Northwest Pipeline's existing plants. The partnership plans to market at least 115 million gallons of natural gas liquids in 1982. A condensate gathering operation has been established in the San Juan Basin and a motor gasoline blending and marketing operation at Cortez, Colorado.

Major pipeline expansion

Northwest Pipeline and Texas Eastern/Transwestern filed in January 1982 with the FERC for approval of new facilities required for Northwest Pipeline to deliver up to 325 million cubic feet daily to Texas Eastern and Transwestern.

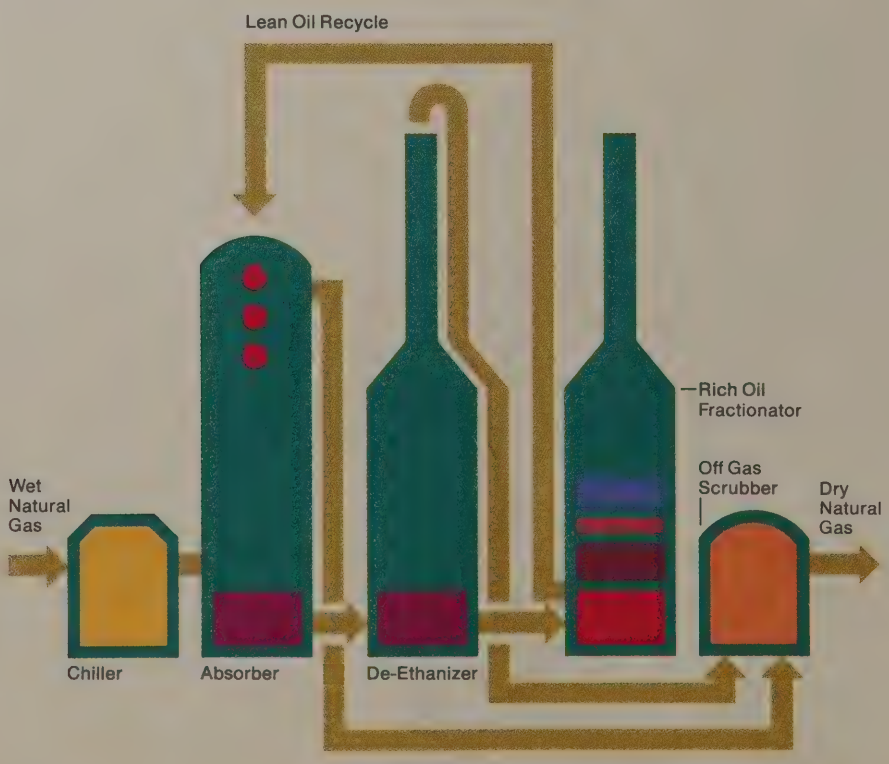
The project will require a $210 million expansion of the Northwest Pipeline transmission system consisting of 243 miles of additional pipeline along its mainline from Rangely to Ignacio, Colorado, a new compressor station at Cortez, Colorado, and an additional compressor unit at an existing station. The project will also require the construction of a new pipeline to connect the Northwest Pipeline system at Ignacio, Colorado with the Transwestern system in central New Mexico.

The new pipeline will cost an estimated $124 million and will consist of 162 miles of 30-inch diameter pipe. A new company, Continental Divide Pipeline Company, to be jointly owned by subsidiaries of Northwest Pipeline and Transwestern, will own the new pipeline. Completion of both the Northwest Pipeline expansion and the Continental Divide Pipeline are currently scheduled for 1983, with construction expected to commence in the fall of 1982, following receipt of final approval from the FERC. The Continental Divide Pipeline will enable natural gas to be delivered through interconnecting pipeline systems to markets in southern California and along the East Coast.

With respect to the LaBarge Low-BTU Gas Project in southwestern Wyoming, Northwest Pipeline in 1981 filed both a petition with the FERC requesting jurisdictional status for the project and a right-of-way application with the Bureau of Land Management.

The proposed processing plant would treat up to 400 million cubic feet daily of low-BTU gas from the LaBarge Anticline, recovering about 80 million cubic feet daily of pipeline-quality gas, and marketable by-products consisting of 240 million cubic feet daily of carbon dioxide and 670 tons per day of sulfur. In its filing with the FERC, Northwest estimated approximately 7 trillion cubic feet of pipeline-quality gas can be recovered.

Preliminary engineering and design studies for the processing plant are under way and should be completed within two months. Cost of the plant is currently estimated at approximately $500 million in 1981 dollars.



Northwest Pipeline's processing plant at Opal, Wyoming, right, removes liquid hydrocarbons from the natural gas. The gas is chilled (see illustration), then percolated through towers where lean oil absorbs the liquid hydrocarbons, which are later separated in the rich oil fractionator.

Exploration and Production

Northwest Exploration Company had an outstanding year in 1981. Accomplishments included (1) oil and gas discovery wells in North Dakota, Wyoming, Colorado and Nevada; (2) a record increase in net proved oil reserves; (3) a substantial boost in net proved gas reserves; (4) continued enlargement of the company's leasehold inventory; and (5) an increase in operating income from $1.2 million in 1980 to $4.7 million in 1981.

Northwest Exploration drilled or participated in drilling 15 development wells and 20 exploratory wells during 1981. Of the total wells drilled, 16 were completed as producing oil or gas wells. The success rate for development wells was 80% and the rate for exploratory wells was 20%.

Proved reserves of oil increased from 1.2 million barrels at the beginning of 1981 to 6.8 million barrels at the beginning of 1982. Net proved gas reserves increased from 45.7 billion cubic feet to 59.4 billion cubic feet in the same time period. The company also boosted its net leaseholds by nearly 100,000 acres during 1981. (See page 18 for a listing of leasehold acreage.)

Northwest Exploration has the largest capital budget in its history for 1982. Plans are to drill or participate in drilling 64 development wells and 19 exploratory wells. The total drilling budget is approximately $43 million with an additional $10 million budgeted for the acquisition of new leasehold acreage.

Net natural gas production at the end of 1981 reached five million cubic feet per day, an increase of 61% over the same period a year ago.

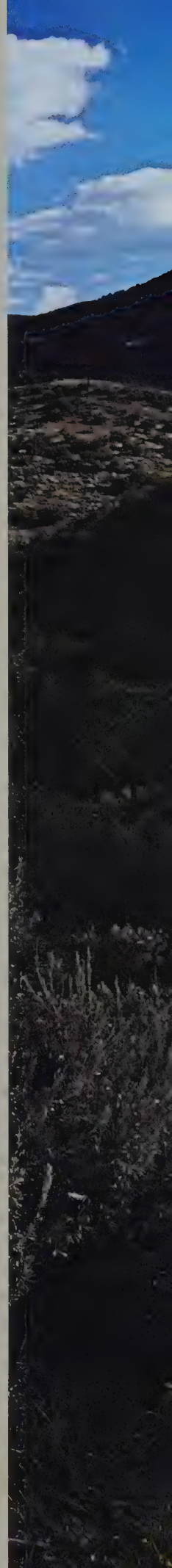
Much of the gas production is from the Rulison Field. Since 1979, Northwest Exploration has drilled 41 wells in the Wasatch and Mesa Verde zones to develop the field. Northwest Exploration has working interests in these wells ranging from 37½% to 100%. Production has been connected to a gathering system and the field is currently producing approximately 5.9 million cubic feet a day. The Rulison Field development is part of the heavy drilling activity occurring in western Colorado's Piceance Basin.

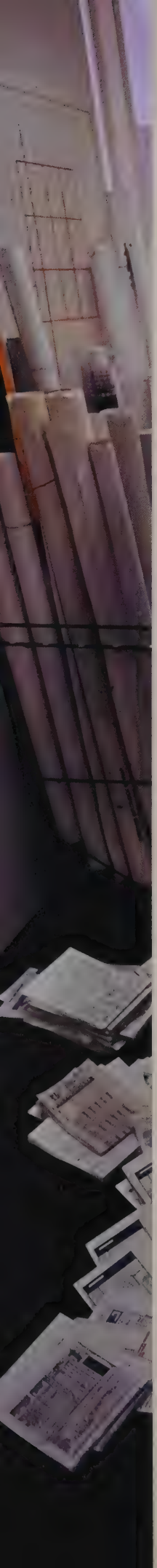
Further development drilling

Plans in 1982 at Rulison include the drilling of 25 additional Wasatch wells and 12 more Mesa Verde wells. A 13,500-foot exploratory well is planned to test a deeper horizon in the Rulison Field.

Another Piceance Basin field is Philadelphia Creek, where Northwest Exploration has 35 wells producing from the Mancos B formation, an extremely tight sandstone. Production exceeds 1.7 million cubic feet per day. Six additional wells are presently awaiting completion.

Geologists and a geophysicist, left, assess data for Northwest Exploration. Map shows the principal Rocky Mountain geological basins and indicates Northwest Exploration's oil and gas discoveries.





In 1981, the company's leaseholds were used to support the drilling by others of 38 wildcat wells. At year-end, this had resulted in four oil wells and nine gas wells. Northwest generally has an overriding royalty interest in the discovery well, reverting to a working interest after payout and the option to participate in subsequent wells or to drill on our own acreage in the vicinity of the discovery. The total cost of the 38-well program was approximately $54 million. This allows Northwest Exploration to evaluate its leasehold acreage, leveraging financial resources to achieve optimum exploration success and to maximize profits.

Purchases oil property

Northwest Production Company was formed in 1981 to purchase a one-half interest in a producing oil property in the Slaughter Field, Hockley County, Texas. During 1982, Northwest Production and its partner, Energy Ventures, Inc. of Houston, plan to drill additional development wells and conduct secondary recovery operations. Independent studies confirm that the properties purchased contain up to 2½ million barrels of proved oil reserves.

Another exploratory venture which may prove to be important is a 6% interest which Northwest Argentina Corporation has in two exploratory wells being drilled in the Acambuco concession in the Northwest Basin in Argentina. One of the wells shows indications of being a significant gas discovery. Both wells are still drilling. Bridas S.A.P.I.C. is operator for the partnership which obtained the government concession covering 528,000 acres in the area of the discovery.

Management believes that these exploration and production operations will enhance the company's future profitability substantially and will provide excellent opportunities for growth.

Following is Northwest Exploration's leasehold inventory by geological area as of January 1, 1982:

Geological Area:	Gross Acres	Net Acres
Big Horn Basin	7,630	7,330
Chadron Arch	70,910	70,830
Denver Basin	27,295	25,370
East Columbia Basin	142,665	142,360
Great Basin	335,440	152,375
Green River Basin	119,345	106,355
Hingeline	38,110	33,750
Las Animas Arch	9,060	5,300
Paradox Basin	2,960	1,100
Piceance Basin	75,660	59,415
Powder River Basin	13,110	10,050
San Juan Basin	32,110	29,960
Sand Wash Basin	28,975	21,990
Utah-Wyoming Overthrust	22,880	20,490
Uinta Basin	8,900	6,370
Uinta Uplift	2,400	2,400
West Columbia Basin	121,960	117,160
Williston Basin	137,040	84,310
Wind River Basin	41,600	40,300
Total Leases	1,238,050	937,215

The Overthrust Belt stretches the entire length of the North American continent and derives its name from earth movements thrusting older strata over younger formations, as illustrated. Right, exploratory rig drills in Colorado.

Alaskan Pipeline Project

A waiver package signed into law in December 1981 cleared the way for project sponsors to commence development of a private sector financing plan which will allow the major North Slope Alaska gas producers—Exxon, Arco and Sohio—to participate in equity financing with the gas industry sponsors of the Alaska Natural Gas Transportation System (ANGTS). The waiver package was designed to remove government obstacles forbidding participation by the North Slope producing companies.

In addition, the waiver package authorizes the FERC to approve a tariff that will provide lenders with sufficient assurances of repayment of funds needed for private financing of the project. It permits expedited treatment of remaining federal regulatory approvals and the inclusion of a North Slope conditioning plant as an integral part of the ANGTS.

A lawsuit was filed January 28, 1982 seeking to thwart the will of Congress by overturning its approval of the waiver package. The Company believes the suit is totally without foundation or merit but is concerned about its potential for delay.

Northwest Alaskan Pipeline Company is heading the partnership which will build the Alaskan segment. Included in the partnership are all the U.S. gas transmission companies that have contracted to purchase Alaskan North Slope gas. Together these companies supply natural gas directly or indirectly to 48 states, and they deliver nearly 40% of all gas transported within the continental U.S.

The transportation system will tap the vast reserves of natural gas beneath the Prudhoe Bay region on Alaska's North Slope. In excess of 26 trillion cubic feet, these proven reserves represent the largest accumulations of natural gas ever discovered in the United States. In addition, geologists estimate that potential reserves on the North Slope could range from 100 to 200 trillion cubic feet.

The waiver of law passed in December has made it possible for the three major Prudhoe Bay producers, Exxon, Arco and Sohio, to participate in equity financing. These producers control approximately 85% of the gas reserves at Prudhoe Bay. The State of Alaska, by virtue of its royalties, owns 12½% of the field. All other producers collectively own 2½%.

Four major sections

The 4,800-mile pipeline will be built in four major sections: Alaskan, Canadian, Western Leg and Eastern Leg. The initial phase of the Western Leg is complete both in the U.S. and Canada; portions of the U.S. and Canadian Eastern Leg are under construction and scheduled for completion in the

Rig at left takes borehole samples next to the Trans Alaska Oil Pipeline. The Alaska Gas Pipeline, as shown on the map, will parallel oil line route from Prudhoe Bay past Fairbanks, then move east into Canada's Yukon Territory.

fall of 1982. The remaining segments are anticipated to be completed in 1987.

ANGTS will provide a transportation service for Prudhoe Bay producers and gas pipeline companies in the lower 48 states. It will have an initial capacity of 2.0 billion cubic feet of gas per day and can be expanded to transport 3.2 billion cubic feet. Approximately 70% of the gas transported through the pipeline system will go to the Midwest, the East and the South and about 30% to the West.

Financing plan under development

The financing plan for the Alaska facilities is being developed by the project partners, the major Prudhoe Bay gas producers and four of the largest U.S. banks. The Canadian companies are developing their financing plan in conjunction with major Canadian banks. Billions of dollars of project equity, as well as a significant level of debt support, will be provided by pipeline sponsors and the major North Slope gas producers. Because of the very large debt requirements and the limitations on U.S. institutions, it is anticipated that more than half of the debt will come from foreign sources. After completion and when the ANGTS is operational pursuant to satisfactory tariff and tracking arrangements, the credit of the project itself will provide adequate assurances of debt service. Alaska's governor has recently established a committee to explore possible state participation in financing of the ANGTS.

Preconstruction effort continues

Engineering design and environmental studies began several years ago in preparation for construction in Alaska. The Engineering Project Management contractor is Fluor Engineers and Constructors, Inc. of Irvine, California for the pipeline system. Ralph M. Parsons Company of Pasadena, California is the contractor for engineering and design work for the gas conditioning plant. Northwest, Fluor and Parsons have assembled a team of over 1,000 experienced cost estimators, cost engineers, design engineers, environmental and other experts representing every discipline necessary for estimating, designing, engineering, constructing and controlling the cost of a project of the magnitude of the ANGTS. Collectively, Northwest, Fluor, Parsons and other consultants with proven Arctic experience have spent over three years and over one million man-hours on the design and engineering of the Alaskan segment, including numerous highly technical field programs to ensure the correct design.

Because of Alaska's harsh environment, rugged terrain and permafrost conditions, the Alaskan portion of the system will represent the greatest construction challenge. It will involve construction of the gas conditioning plant and related facilities at Prudhoe Bay, 745 miles of 48-inch diameter pipe extending from Prudhoe Bay to the Alaska-Yukon border, seven compressor stations, 17 pipeline work

Map shows the entire 4,800-mile route of the ANGTS. Approximately 30% of the pipeline mileage will be complete this year when portions of the Eastern Leg are operational. The initial phase of the Western Leg was placed in service in October 1981.

camps, seven compressor station camps, 14 refrigeration units, 12 airfields and four operations and maintenance facilities.

The most extensive of the Alaskan field studies is frost-heave testing to determine the effects of freezing and thawing on the buried pipeline in Alaska. Additional field studies in 1981 included borehole drilling to determine subsurface soil and frost conditions, controlled blasting and trench excavation, river and stream crossing surveys and several other technical field procedures.

Early construction continues

Canadian gas began flowing through the completed portion of the Western Leg on October 1. The pipeline, which can deliver up to 300 million cubic feet per day to customers in southern California, was constructed in the United States by Pacific Gas Transmission Company, a subsidiary of Pacific Gas and Electric Company of San Francisco. The Canadian section was built by Foothills Pipe Lines (Yukon) Ltd. as part of existing pipeline systems in Alberta and British Columbia.

The initial phase of the U.S. Eastern Leg, 823 miles of 42-inch diameter pipeline, is being built by Northern Border Pipeline Company. This segment is scheduled for completion in the fall of 1982. It will connect with the Canadian Eastern Leg, now nearing completion, to initially deliver up to 975 million cubic feet of gas per day to customers in midwestern and eastern U.S. markets. Ultimately, the U.S. Eastern Leg will traverse some 1,131 miles from Montana to Dwight, Illinois.

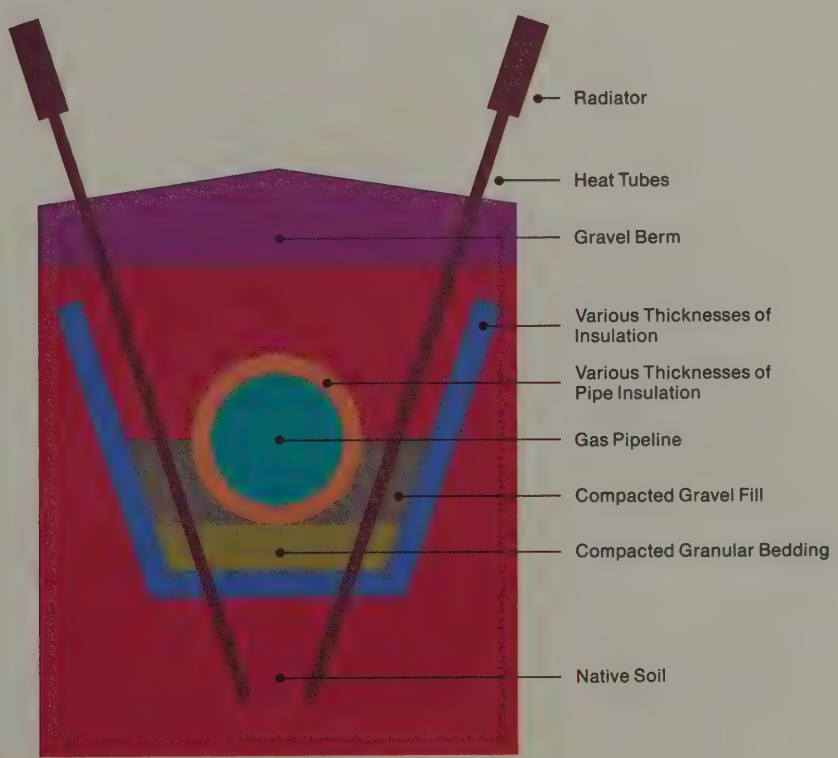
Northern Border Pipeline Company is a consortium of five gas transmission companies including Northwest Border Pipeline Company, a subsidiary of Northwest Energy Company. Northwest Border has a 12¼% equity ownership in the pipeline. The company is currently realizing earnings from the allowance for equity funds used during construction, and upon completion of construction will realize earnings from operations and investment tax credits. With the completion of initial construction of the U.S. Eastern Leg in the fall of 1982, 30% of the pipeline mileage of the ANGTS will be complete.

Reduces U.S. dependence

The Alaskan project initially will reduce U.S. dependence on foreign oil by replacing at least 400,000 barrels per day of imported oil and substantially reducing the nation's foreign payments. The ANGTS will also create jobs for American workers and orders for U.S. businesses.

Alaskan gas will not be subject to OPEC price increases or embargoes. It will be an assured source of energy for the benefit of a wide variety of U.S. gas consumers. In addition, the Alaskan project will stimulate natural gas exploration in Alaska and Canada and produce a net national economic benefit to the U.S. ranging from $40 billion to $90 billion.

The composite diagram illustrates several methods being tested to control frost heave. Each method will be used independently as soil conditions require. Buried pipe sections are under study at seven locations along the route of the pipeline in Alaska.



Coal Operations

The Company's coal operations are carried out primarily by Northwest Coal Corporation, whose wholly owned subsidiary owns and operates an underground mine in western Colorado, producing high-BTU, low-sulfur, bituminous coal.

Coal operations have been adversely affected by low market prices and high operating and transportation costs. In 1981, the coal operations generated an operating loss of approximately $6.5 million, before income tax benefits and financial costs.

While near-term improvement in results from coal operations does not appear promising, management is evaluating alternatives and seeking ways to minimize losses and to realize the value of its coal assets in the best manner possible.

The Colorado mine consists of five seams, but only the upper seam is currently being mined. The other four seams contain the same type of coal with varying sulfur content. Aggregate recoverable coal reserves from all seams are estimated at 40 million tons. A coal-washing facility, placed in operation in January 1980, enables Northwest Coal to remove impurities from coal and thereby raise its BTU value. In addition, the company placed a unit-train loadout facility in operation in late 1979. The loadout facility has a capacity of 8,000 tons of coal and can load 80-car unit-trains in less than two hours. This facility allows Northwest Coal to provide coal to its customers at lower transportation rates.

Production from the mine reached 696,000 tons in 1981, substantially over the 1980 total of 435,000 tons. Northwest Coal plans to mine over 800,000 tons in 1982.

Improved operating efficiency

Tons produced per man-day worked jumped from 7.19 in 1980 to 11.05 in 1981, reflecting the use of the longwall system and better utilization of manpower. The cost per ton of coal produced also dropped by approximately $5 per ton as a result of improved operating efficiency. Management is quite hopeful that even greater efficiency can be realized.

The main purchaser of coal from the mine is Central Illinois Light Company (CILCO), Peoria, which has a contract to purchase a minimum of 600,000 tons per year. It is likely that CILCO will purchase the mine's entire production in 1982.

Coal produced at the Colorado mine can be used as soft coking coal for blending in steel mills. As a result, Northwest Coal entered this market in 1980 with some sales to Japan, which reached 60,000 tons in 1981 and may result in long-term contracts in the future.

The longwall production unit utilizes hydraulic roof supports (see illustration), while shearers cut coal from the face of the mine. At right, miners operate the longwall system at Northwest's mine in western Colorado.

Financial Review 1981

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This processing plant at Ignacio, Colorado removes liquid hydrocarbons from natural gas produced in the San Juan Basin. The resulting liquid products—butane, propane and natural gasoline—are stored at the plant and marketed throughout the region.

Management's Discussion and Analysis

The following discussion is provided to assist your understanding of the Company's results of operations and financial condition for the three years ended December 31, 1981.

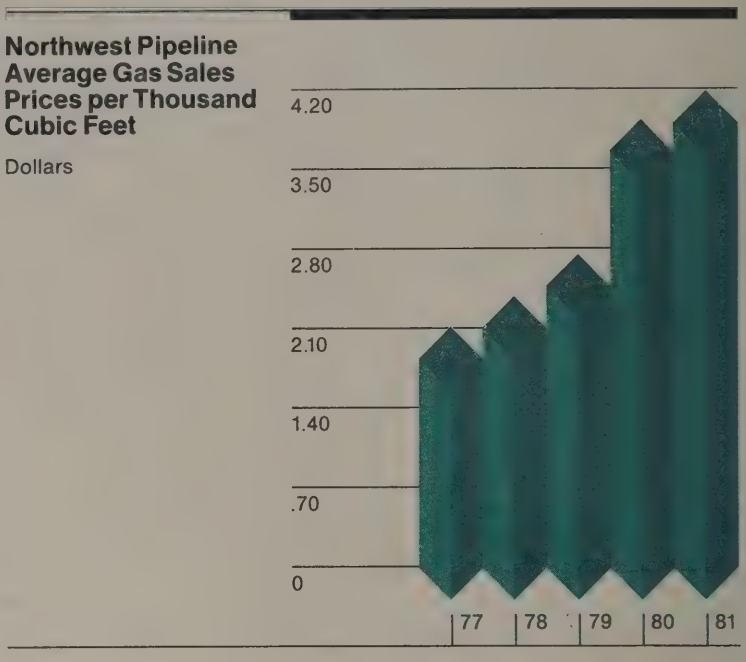
Operating Results

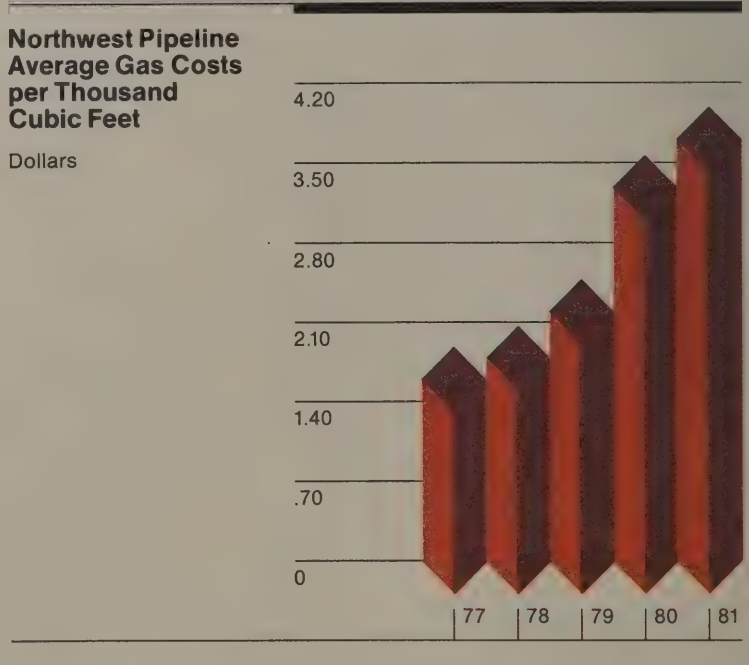
During the three years ended December 31, 1981, Northwest Pipeline Corporation ("Pipeline") has accounted for substantially all of the consolidated net income of the Company. Despite Pipeline's reduction in sales volumes of 94 billion cubic feet ("BCF") in 1980 from 1979 and 10 BCF in 1981 from 1980, it has been successful in maintaining significant increases in net income, due primarily to investment tax credits generated from property, plant and equipment additions, plus achievement of a satisfactory return on an increasing rate base. The reduction in sales volumes was anticipated by Pipeline in its rate filings, resulting in operating expenses (net of other operating revenues, such as extracted product sales) and other cost of service components being recovered over the lesser sales volumes.

Pipeline's gross margin (natural gas sales minus gas purchases and gas royalties) increased by approximately 13% from 1979 to 1980 and by approximately 14% from 1980 to 1981. The major causes for these increases can be attributed to increased revenue generated through a higher rate base, plus, starting October 1, 1981, an increase in the overall rate of return on rate base from 10.68% to 13.92% as filed for in Pipeline's most recent rate case.

Pipeline spent over $212 million for capital expenditures on transmission, gas supply and production and drilling projects during 1981, including the 351-mile expansion of its existing transmission line to accommodate early delivery of Alberta natural gas to California markets in conjunction with the Alaska Highway Pipeline Project. These expenditures significantly reduced the Company's effective income tax rate through higher investment tax credits. Comparable expenditures by Pipeline for 1980 and 1979 were approximately $161 million and $74 million, respectively.

One of the most significant increases in the Company's Consolidated Statement of Income for 1981, compared with 1980, is the nearly $25 million increase in interest expense, net of an increase of approximately $15 million in allowance for borrowed funds used during construction, principally applicable to short-term interest. An increase in interest expense of $16 million on long-term debt resulted from issuance in July 1981 of $40 million of 9% convertible subordinated debentures, representing a first offering in the Eurodollar market, Pipeline's issuance of $100 million of 16¾% sinking fund debentures during May 1981 and the issuance of $90 million in variable-interest-rate bank term-loans during September 1981. Increases in interest expense for Pipeline were anticipated in Pipeline's most recent rate filing and, therefore, were substantially covered through increased gas sales rates. The Company's level of short-term borrowings in relation to the previous year's level also had a significant impact on interest expense (approximately a $24 million increase) in 1981. Draw-downs on the Company's line-of-credit arrangements averaged $140 million





during 1981, compared with $11 million during 1980, due primarily to the extensive capital expenditures (discussed above) and general corporate requirements. Also, the weighted average short-term interest rate during 1981 was approximately 18%, compared with approximately 16% for 1980.

For the periods presented, Northwest Energy Company ("Energy") has recognized its pro rata share of allowance for equity funds capitalized resulting from its participation in the Alaska Highway Pipeline Project (see Note 2 of Notes to Consolidated Financial Statements). As the equity base in the Project increases, the allowance for equity funds capitalized also increases. For the three years ended December 31, 1981, Energy has invested approximately $63.7 million of cash in Alaskan Northwest Natural Gas Transportation Company and Northern Border Pipeline Company. The allowance for equity funds capitalized for that period amounted to $22.7 million.

One significant consolidated expense item which increased considerably, particularly in 1980 over 1979, was operation and maintenance expense. While Pipeline's portion of the increase was substantial, due to employee-related and inflationary increases, such increases were partially anticipated and recovered through the rate-making process described above. Over half of the consolidated increase in 1980, however, was attributable to operations of other subsidiaries, particularly a coal subsidiary, in which the increased operating costs were partially offset by increased sales revenues, thereby not materially affecting net income.

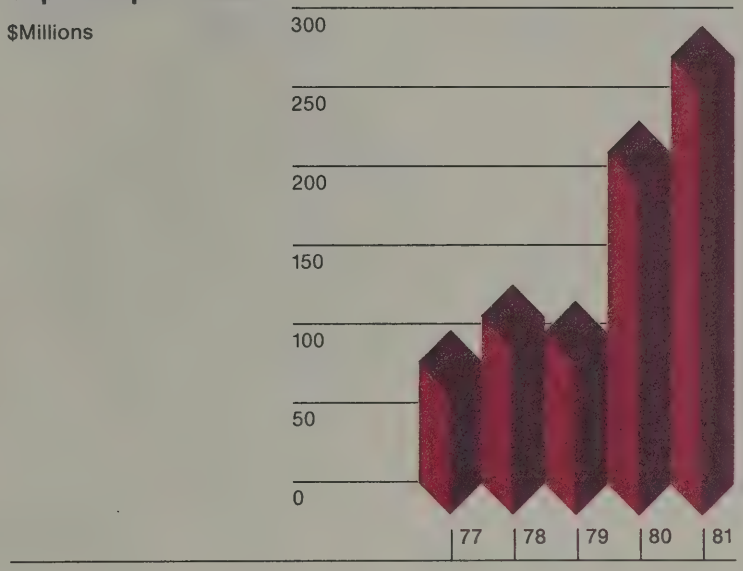
Although the impact on 1981 consolidated operating income (approximately $4.7 million) from Northwest Exploration Company ("Northwest Exploration") was not material, this company has now reached a stage where its future contribution to consolidated profitability could be substantial. Management believes that Northwest Exploration's net leasehold position, once proved and developed, can provide sizable returns on the funds invested. Consequently, the Company has budgeted over $43 million in 1982 for drilling expenditures.

On a less positive note, the Company's coal operations continued to generate an operating loss, which for 1981 amounted to approximately $6.5 million. Such operations have been plagued with low market prices, coupled with high operating and transportation costs. In addition, the Company found it necessary to abandon certain properties that cannot be economically mined at the present market prices. Although near-term improvement in the results from coal operations does not appear promising, management is moving ahead to develop the most economically feasible plans to minimize the Company's exposure to further losses.

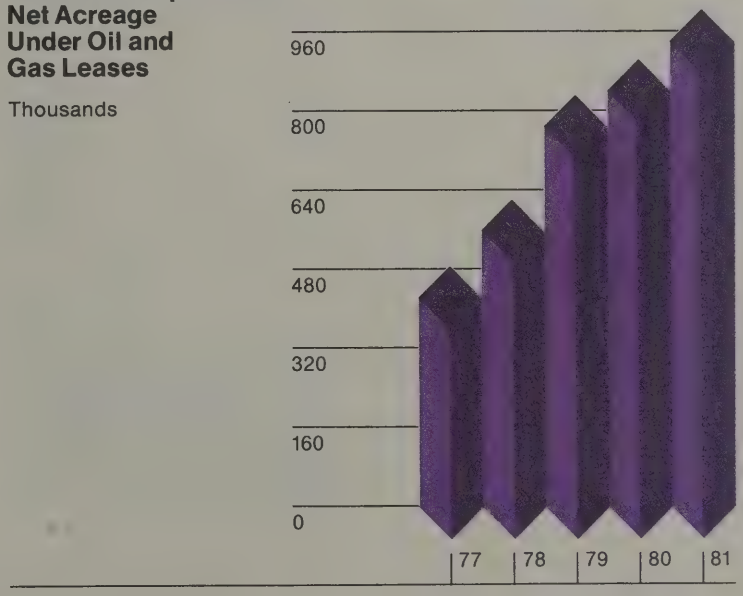
Capital Resources and Liquidity

During the three-year period ended December 31, 1981, the Company expended approximately $571.2 million for property, plant and equipment additions, plus $63.7 million for the Alaska Highway Pipeline Project. As evidenced by the

Consolidated Capital Expenditures



Northwest Exploration Net Acreage Under Oil and Gas Leases

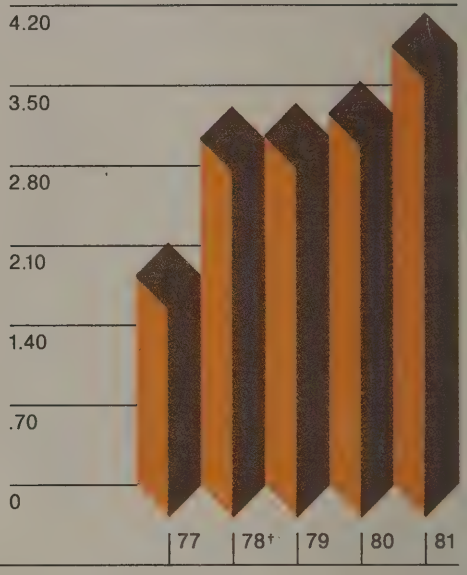


Distribution of 1981 Consolidated Operating Revenues

- Gas purchases and royalties
- Operation and maintenance
- Net income to common
- Depreciation, depletion and amortization
- Interest
- Taxes

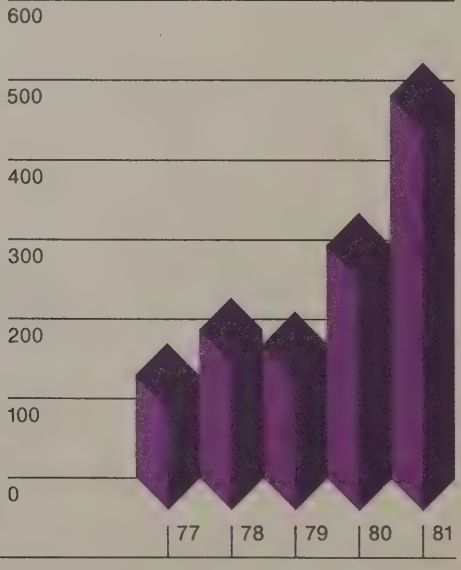
Primary Income per Share Applicable to Common Stock*

Dollars

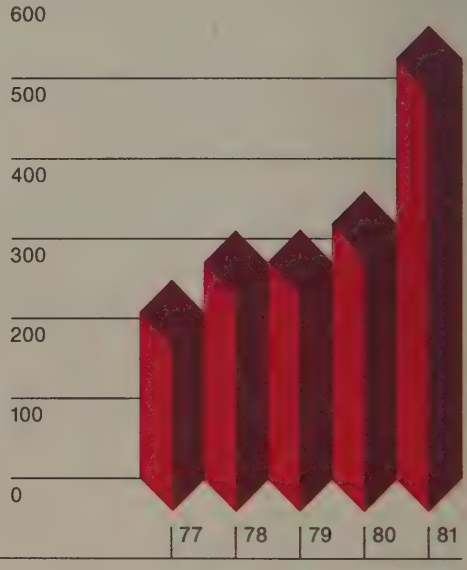


*Restated to reflect a 100% common stock distribution on June 8, 1979 and a 50% distribution on September 12, 1980.
†Includes extraordinary items of $1.20 per share.

Northwest Pipeline Gathering System Mileage Additions



New Wells Connected to Northwest Pipeline System



accompanying graph, a significant portion of these expenditures was provided by funds from operations. In addition, the Company has been successful in obtaining external funds through debt and equity markets. The Company's financing since 1978, exclusive of short-term borrowings and secondary offerings, is presented below:

Date	Description of Issue
September 1979	1,800,000 shares of Energy common stock
July 1980	3,000,000 shares of Energy $2.125 cumulative convertible preference stock, Series A
May 1981	$100 million of Pipeline 16¾% sinking fund debentures
July 1981	$40 million of Northwest International Finance 9% convertible subordinated debentures
September 1981	$90 million of variable-interest-rate bank term-loans

The Company anticipates 1982 capital expenditures will total approximately $224.3 million, including approximately $17.1 million for the Alaska Highway Pipeline Project. These capital expenditures are expected to be financed with long-term debt and equity issues, with bank debt and with funds provided from operations. Traditionally the Company has funded its capital expenditure programs on an interim basis with bank debt and has refinanced such bank debt with issues of long-term debt and equity. Such financing practices have provided flexibility in the timing of issuance of long-term securities. With respect to a discussion of financing for the Alaska segment of the Alaska Highway Pipeline Project, see Note 2 of Notes to Consolidated Financial Statements.

At December 31, 1981, the Company's most significant unused source of liquidity consisted of lines-of-credit and available debt capacity under the Company's existing indentures. The unsecured line-of-credit arrangements available to the Company were $597 million, $430 million and $159 million at December 31, 1981, 1980 and 1979, respectively. Management believes that the Company has adequate interim financing capacity from these bank credit arrangements, but will secure additional lines as business circumstances dictate.

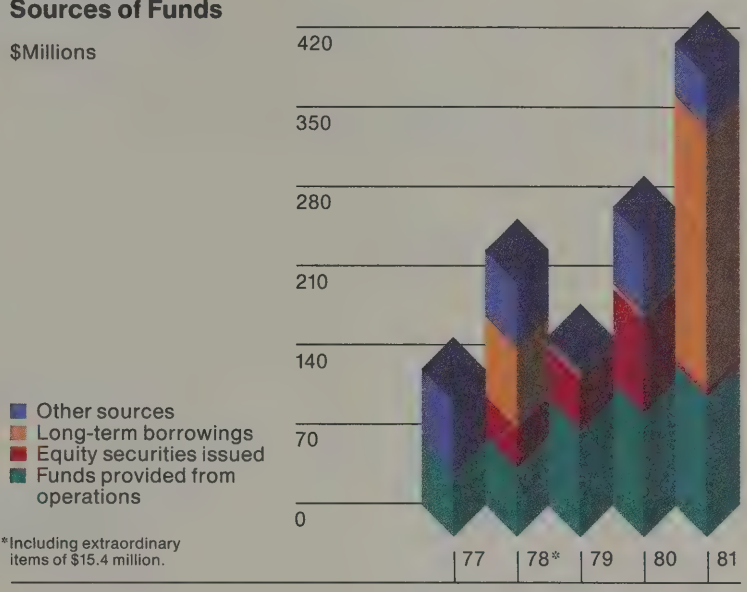
One aspect of the Company's business which indirectly provides a measure of liquidity and the ability to secure capital, is Pipeline's available gas supply. This status is measured by a reserve life index, which for Pipeline is estimated at 21.6 years and is the highest of any major gas transmission company in the United States.

Inflation

All areas of the Company are confronted with the ever-increasing cost of labor and materials as a result of inflation. The ability to recover these increases through revenues, without eroding net income, is contingent upon market conditions for gas and oil production and the regulatory response by FERC in the case of gas transmission operations. Inflationary impact on the Company is addressed in another section of this report, beginning on page 50.

Consolidated Sources of Funds

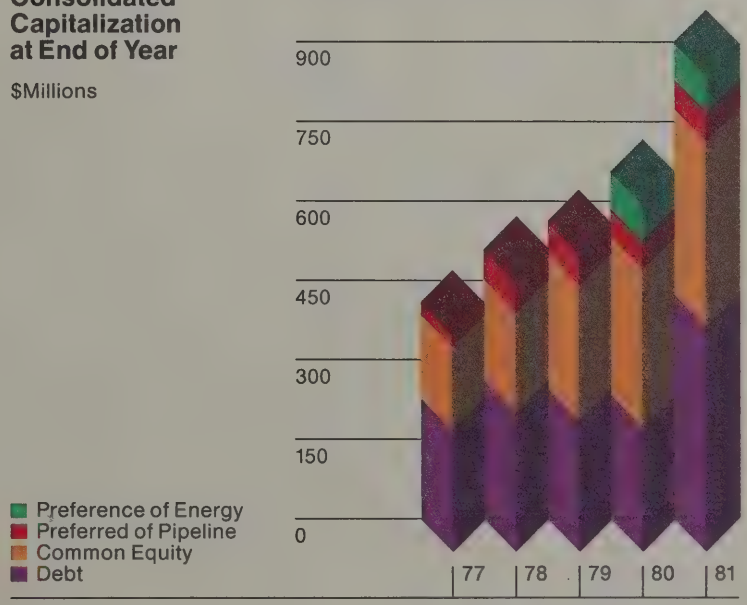
$Millions



*Including extraordinary items of $15.4 million.

Consolidated Capitalization at End of Year

$Millions



Consolidated Balance Sheet

(Dollars in Thousands)

Northwest Energy Company and Subsidiaries

December 31,	1981	1980
Assets		
Property, Plant and Equipment, at cost	**$1,250,137**	$ 940,392
Less—Accumulated depreciation, depletion and amortization	**358,159**	321,206
	891,978	619,186
Construction work in progress	**45,156**	92,140
	937,134	711,326
Investments:		
Alaska Highway Pipeline Project (Note 2)—		
Alaskan Partnership	**62,161**	48,822
Northern Border	**52,334**	5,321
Other	**21,723**	10,578
	136,218	64,721
Current Assets:		
Cash and temporary cash investments	**35,599**	13,463
Accounts receivable	**223,577**	166,308
Exchange gas due from others, net	**15,796**	3,011
Federal and state income taxes receivable (Note 8)	**19,028**	2,987
Gas stored underground (at average cost)	**84,660**	79,426
Inventories (principally at average cost)	**37,446**	20,811
Costs recoverable through rate adjustments	**22,392**	—
Prepayments and other	**14,331**	6,717
	452,829	292,723
Deferred Charges	**11,771**	4,837
	$1,537,952	$1,073,607

The accompanying notes to consolidated financial statements are an integral part of this consolidated balance sheet.

	1981	1980
Liabilities and Stockholders' Equity		
Capitalization:		
Common stockholders' equity (Note 4)—		
Common stock, par value $1 per share, authorized 80,000,000 shares; outstanding 16,241,990 and 16,023,821 shares, respectively	**$ 16,242**	$ 16,024
Additional paid-in capital	**147,994**	142,635
Retained earnings (Note 6)	**193,425**	148,240
	357,661	306,899
Less—Obligation from the Trustee of the Bonus Employee Stock Ownership Plan (Note 11)	**5,587**	5,916
	352,074	300,983
Preference stock, issuable in series, par value $1 per share, authorized 10,000,000 shares; outstanding 2,999,500 and 3,000,000 shares, respectively; cumulative convertible, Series A (Note 4)	**71,188**	71,200
Preferred stock issues of Northwest Pipeline Corporation, subject to periodic redemption (Note 4)	**52,480**	53,750
Long-term debt, less current maturities (Note 5)	**420,531**	229,567
	896,273	655,500
Current Liabilities:		
Current maturities of long-term debt (Note 5)	**39,434**	19,778
Notes payable to banks (Note 7)	**224,546**	39,320
Accounts payable	**203,540**	187,615
Accrued taxes, other than income taxes	**6,549**	5,858
Accrued interest	**15,182**	5,379
Costs refundable through rate adjustments	**—**	28,872
Reserve for estimated rate refunds	**—**	7,025
Accrued payroll and benefits	**15,368**	10,489
Other	**12,107**	8,852
	516,726	313,188
Accumulated Deferred Income Taxes (Note 8)	**124,953**	104,919
Commitments and Contingencies (Notes 2, 3 and 12)		
	$1,537,952	$1,073,607

Consolidated Statement of Income

(Dollars in Thousands, Except Per Share Amounts)

Northwest Energy Company and Subsidiaries

Year Ended December 31,	1981	1980	1979
Operating Revenues (Notes 3 and 9)	**$1,398,809**	$1,323,432	$1,119,532
Operating Expenses:			
Gas purchases	**1,020,974**	1,012,221	851,541
Gas royalties	**65,935**	55,062	65,549
Operation and maintenance	**131,177**	107,801	73,254
Depreciation, depletion and amortization	**39,459**	30,903	28,229
Taxes, other than income taxes	**14,617**	12,577	10,344
Income taxes (Note 8)	**16,571**	34,123	28,428
	1,288,733	1,252,687	1,057,345
Operating Income	**110,076**	70,745	62,187
Other (Income) and Income Deductions:			
Interest charges	**67,747**	27,764	26,953
Allowance for borrowed funds used during construction	**(20,068)**	(4,854)	(2,304)
	47,679	22,910	24,649
Pro rata share of allowance for equity funds capitalized during engineering, design and construction (Note 2)—			
Alaskan Partnership	**(7,650)**	(6,105)	(4,191)
Northern Border	**(4,251)**	(385)	(108)
Dividend requirements on preferred stock issues of Northwest Pipeline Corporation	**5,090**	5,240	5,304
Other, net	**111**	(3,984)	(3,408)
Allowance for equity funds used during construction	**(1,044)**	(1,006)	(1,326)
	39,935	16,670	20,920
Net Income	**70,141**	54,075	41,267
Less—Preference stock dividend requirement	**6,374**	2,728	—
Net Income Applicable to Common Stock	**$ 63,767**	$ 51,347	$ 41,267
Income Per Share Applicable to Common Stock and Common Stock Equivalents:			
Primary	**$ 3.83**	$ 3.23	$ 3.03
Fully diluted	**3.64**	3.16	3.01
Weighted Average Number of Common Shares and Common Stock Equivalents Outstanding, in thousands:			
Primary	**16,882**	15,876	13,600
Fully diluted	**19,510**	17,099	13,719
Dividends Declared Per Share of Common Stock	**$ 1.15**	$ .95	$ .85

The accompanying notes to consolidated financial statements are an integral part of this consolidated statement.

Consolidated Statement of Changes in Financial Position

(Dollars in Thousands)

Northwest Energy Company and Subsidiaries

Year Ended December 31,	1981	1980	1979
Source of Funds:			
Operations—			
Net income	**$ 70,141**	$ 54,075	$ 41,267
Nonfund income items:			
Depreciation, depletion and amortization	**39,459**	30,903	28,229
Deferred income taxes—noncurrent (Note 8)	**23,460**	25,520	23,790
Pro rata share of allowance for equity funds capitalized during engineering, design and construction (Note 2)—			
Alaskan Partnership	**(7,650)**	(6,105)	(4,191)
Northern Border	**(4,251)**	(385)	(108)
Allowance for equity funds used during construction	**(1,044)**	(1,006)	(1,326)
Other	**3,669**	4,430	5,332
Total funds from operations	**123,784**	107,432	92,993
Other sources—			
Equity securities issued	**4,957**	81,600	45,351
Long-term borrowings (Note 5)	**230,565**	4,222	518
Decrease in working capital	**43,432**	65,360	—
Other	**2,297**	2,652	2,633
Total source of funds	**$405,035**	$261,266	$141,495
Use of Funds:			
Additions to property, plant and equipment	**$269,018**	$207,953	$ 95,189
Investments, excluding allowance for equity funds capitalized (Note 2)—			
Alaskan Partnership and Northern Border	**48,451**	9,400	5,862
Other	**10,326**	792	675
Reduction in long-term debt	**39,649**	20,244	16,631
Cash dividends	**24,956**	17,812	11,584
Increase in working capital	**—**	—	2,648
Other	**12,635**	5,065	8,906
Total use of funds	**$405,035**	$261,266	$141,495
Changes in Components of Working Capital:			
Cash and temporary cash investments	**$ 22,136**	$ 7,697	$ (3,654)
Accounts receivable	**57,269**	(6,163)	56,280
Gas stored underground	**5,234**	28,605	5,062
Inventories	**16,635**	7,541	2,215
Costs recoverable/refundable through rate adjustments	**51,264**	(50,290)	(5,951)
Current maturities of long-term debt	**(19,656)**	(3,436)	1,628
Notes payable to banks	**(185,226)**	(39,320)	9,000
Accounts payable	**(15,925)**	(52,835)	(42,469)
Accrued taxes, including income taxes	**15,350**	22,611	10,960
Reserve for estimated rate refunds	**7,025**	20,710	(23,866)
Other	**2,462**	(480)	(6,557)
Total increase (decrease) in working capital	**$ (43,432)**	$ (65,360)	$ 2,648

The accompanying notes to consolidated financial statements are an integral part of this consolidated statement.

Consolidated Statement of Capitalization

(Dollars in Thousands)

Northwest Energy Company and Subsidiaries

Year Ended December 31,	1981	1980	1979
Common Stockholders' Equity (see accompanying Consolidated Statement of Common Stockholders' Equity and Note 4):			
Common stock	**$ 16,242**	$ 16,024	$ 10,495
Additional paid-in capital	**147,994**	142,635	141,497
Retained earnings (Note 6)	**193,425**	148,240	111,977
	357,661	306,899	263,969
Less—Obligation from the Trustee of the Bonus Employee Stock Ownership Plan (Note 11)	**5,587**	5,916	6,244
Total common stockholders' equity	**352,074**	300,983	257,725
Preference Stock of Northwest Energy Company (Note 4):			
Issuable in series, par value $1 per share, authorized 10,000,000 shares; outstanding at December 31, 1981 and 1980, 2,999,500 and 3,000,000 shares, respectively; cumulative convertible, Series A—			
Balance at beginning of period	**71,200**	—	—
Proceeds from the issuance of 3,000,000 shares (net of $3,800 of issuance costs)	**—**	71,200	—
500 shares converted into common stock	**(12)**	—	—
Balance at end of period	**71,188**	71,200	—
Preferred Stock Issues of Northwest Pipeline Corporation (Note 4):			
Issuable in series, par value $1 per share, authorized 10,000,000 shares; outstanding, 699,200 shares, 750,000 shares and 800,000 shares at December 31, 1981, 1980 and 1979, respectively, cumulative $2.50 series; and 1,400,000 shares, cumulative $2.36 series; both series subject to periodic redemption—			
Balance at beginning of period	**53,750**	55,000	55,000
Preferred stock redeemed for sinking fund requirements	**(1,270)**	(1,250)	—
Balance at end of period	**52,480**	53,750	55,000
Long-Term Debt, less current maturities of $39,434, $19,778 and $16,342, respectively (Note 5):			
First Mortgage Pipe Line Bonds, 4.675%-6% series, due 1984-1986	**13,119**	20,920	28,721
Sinking Fund Debentures, 5⅜%-16¾% series, due 1984-2001	**286,144**	205,066	215,969
Convertible Subordinated Debentures, 9%, due 1996	**40,000**	—	—
Variable-interest-rate bank term-loans, due quarterly through 1987	**75,000**	—	—
Other	**6,268**	3,581	858
Total long-term debt	**420,531**	229,567	245,548
Total capitalization	**$896,273**	$655,500	$558,273

The accompanying notes to consolidated financial statements are an integral part of this consolidated statement.

Consolidated Statement of Common Stockholders' Equity

(Dollars in Thousands)

Northwest Energy Company and Subsidiaries

Year Ended December 31,	1981	1980	1979
Common Stockholders' Equity (Note 4):			
Common stock, par value $1 per share, authorized 80,000,000 shares; outstanding at end of period, 16,241,990, 16,023,821 and 10,495,372 shares, respectively—			
Balance at beginning of period	**$ 16,024**	$ 10,495	$ 4,304
Par value of 218,169 shares issued in 1981, 231,972 shares issued in 1980 and 1,887,320 shares issued in 1979	**218**	232	1,887
Par value of 5,296,477 shares issued in 1980 and 4,304,026 shares issued in 1979 in connection with 50% and 100% common stock distributions, respectively	**—**	5,297	4,304
Balance at end of period	**16,242**	16,024	10,495
Additional paid-in capital:			
Balance at beginning of period	**142,635**	141,497	104,150
Proceeds, in excess of par value, from common stock issued	**4,739**	6,368	43,464
Excess of stated amount of Northwest Pipeline preferred stock redeemed, over cost of redemption	**206**	83	—
Issuance costs of common stock	**—**	(8)	(1,813)
Transfer of capital in connection with 50% and 100% common stock distributions in 1980 and 1979, respectively	**—**	(5,297)	(4,304)
Other capital transactions	**414**	(8)	—
Balance at end of period	**147,994**	142,635	141,497
Retained earnings (Note 6):			
Balance at beginning of period	**148,240**	111,977	82,294
Net income for period	**70,141**	54,075	41,267
Cash dividends—			
Common stock	**(18,582)**	(15,084)	(11,584)
Preference stock	**(6,374)**	(2,728)	—
Balance at end of period	**193,425**	148,240	111,977
Subtotal	**357,661**	306,899	263,969
Less—Obligation from the Trustee of the Bonus Employee Stock Ownership Plan (Note 11)	**5,587**	5,916	6,244
Total common stockholders' equity	**$352,074**	$300,983	$257,725

The accompanying notes to consolidated financial statements are an integral part of this consolidated statement.

Notes to Consolidated Financial Statements

(1) Summary of Accounting Policies

Consolidation

The consolidated financial statements include the accounts of Northwest Energy Company ("Energy") and all significant wholly owned subsidiaries (the "Company"). All significant intercompany transactions have been eliminated. Northwest Pipeline Corporation ("Pipeline"), the principal subsidiary of Energy, is an interstate natural gas transmission company which owns and operates a pipeline system for the transmission and sale of natural gas in the northwestern United States. Natural gas transmission assets, including the assets of Pipeline and of Northwest Alaskan Pipeline Company ("Northwest Alaskan") and Northwest Border Pipeline Company ("Northwest Border"), discussed below, approximated 86% of consolidated assets at December 31, 1981 and 89% at December 31, 1980. Such operations accounted for more than 97% of consolidated operating revenues and net income for the periods presented.

Energy's investments in the Alaska Highway Pipeline Project (the "Project") (see Note 2, below) have been made through two subsidiaries, Northwest Alaskan and Northwest Border. Northwest Alaskan is a partner in a partnership, Alaskan Northwest Natural Gas Transportation Company (the "Alaskan Partnership"), which will construct and operate the Alaska segment of the Project. Northwest Border is a partner in another partnership, Northern Border Pipeline Company ("Northern Border"), which is constructing and will operate the Northern Border segment of the Project.

Northwest Alaskan's and Northwest Border's investments in the Project are accounted for at cost plus the subsidiaries' pro rata share of allowance for equity funds capitalized during engineering, design and construction. Such investments are carried at amounts which are the same as the subsidiaries' equity in the underlying net assets of the respective partnerships.

Property, Plant and Equipment

Property, plant and equipment, consisting principally of gas transmission and production plant, is recorded at cost which, for properties of Pipeline, represents original cost.

Expenditures which materially increase values or capacities or extend useful lives of property, plant or equipment are capitalized. Routine maintenance, repairs and renewal costs are charged to income as incurred. Gains or losses from the ordinary sale or retirement of property, plant and equipment are charged or credited to accumulated depreciation, depletion and amortization.

Allowance for Borrowed and Equity Funds Used During Construction

Allowance for funds used during construction ("AFUDC") for Pipeline, included in "Other income and income deductions," represents the estimated cost of borrowed and equity funds applicable to utility plant in process of construction. Recognition is made of these items as a cost of utility plant because it constitutes an actual cost of construction and, under established regulatory practices, Pipeline is permitted to recover and earn a return on such costs. The Federal Energy Regulatory Commission ("FERC") has prescribed a formula which is used in computing separate allowances for borrowed and equity funds used during construction.

The composite rate used by Pipeline to capitalize the cost of funds related to construction was approximately 20%, 19% and 15% for 1981, 1980 and 1979, respectively. Such rates include the cost related to compensating balance arrangements with banks.

Depreciation, Depletion and Amortization

Depreciation for Pipeline is provided by the straight-line method for all classes of property, plant and equipment, except producing gas properties. The composite annual depreciation, depletion and amortization ("DD&A") rates for 1981, 1980 and 1979 were 3.97%, 3.94% and 4.09%, respectively. DD&A for gas properties of Pipeline is determined by the unit-of-production method.

Exploration activities, other than Pipeline, are accounted for under the full-cost method, and under this method of accounting the entire full-cost pool of capitalized costs, including undeveloped leasehold costs, is amortized using the unit-of-production method.

For additional information regarding the Company's accounting policies for oil and gas operations, see Note 15.

Coal leases and mine development costs are amortized or depleted using the unit-of-production method, based upon total estimated tons of proved recoverable coal reserves. Coal mining equipment and facilities are depreciated on a straight-line basis over useful lives of from 3 to 20 years.

Federal Income Taxes

Deferred income taxes are provided on substantially all tax timing differences. The tax benefit of the investment tax credit is recognized currently for financial reporting purposes.

Income Per Share Applicable to Common Stock

Primary income per share has been computed by dividing net income applicable to common stock, as adjusted for the after-tax interest on the 9% convertible subordinated debentures, by the weighted average number of common shares and common stock equivalents outstanding during the applicable periods. Shares issuable upon conversion of the 9% convertible subordinated debentures into common stock are classified as common stock equivalents and have been included in the weighted average number of common equivalent shares outstanding.

Fully diluted income per share has been computed based upon the weighted average number of common shares and common stock equivalents outstanding, adjusted by the assumed conversion of Energy's preference stock into common stock and adjusted for shares issuable from the

assumed payment of outstanding Executive Incentive Plan awards. Income for the fully diluted computations has been adjusted for both the interest on the 9% convertible subordinated debentures and the dividend requirement on Energy's preference stock.

Reclassifications
Certain minor revisions and reclassifications have been made in the 1980 and 1979 financial statements to conform with the format followed for the 1981 financial statements.

(2) Investment in the Alaska Highway Pipeline Project
Scope and Organizational Structure of the Project
The Alaska Highway Pipeline Project (the "Project") contemplates construction and operation of a pipeline transmission system to bring natural gas from Prudhoe Bay on the North Slope of Alaska through western Canada to western, midwestern, southern and eastern markets in the lower 48 states. In 1978, Northwest Alaskan Pipeline Company, a wholly owned subsidiary of Energy, and affiliates of major U.S. natural gas transmission companies formed Alaskan Northwest Natural Gas Transportation Company, a general partnership ("Alaskan Partnership"), to construct and operate the Alaska segment of the Project. A Canadian consortium will design, construct and operate natural gas pipelines and related facilities to transport Alaskan gas from the Alaskan-Canadian border across Canada for delivery at two points on the international boundary, one near Kingsgate, British Columbia and the other at Monchy, Saskatchewan. From Kingsgate, a portion of the Alaskan gas will be transported to California and other western states through the expansion of certain existing pipeline facilities, which comprise the Western Leg segment of the Project. During 1981, Pipeline expanded some of its existing facilities in connection with the early construction of a portion of the Western Leg to expedite movement of Canadian gas prior to the flow of Alaskan gas from Kingsgate to southern California. Another subsidiary of Energy is a partner in the Northern Border Pipeline Company, which has under construction and will operate the Northern Border segment of the Project that will deliver Canadian gas to midwestern, southern and eastern markets commencing in late 1982 as a part of phase one of the Northern Border segment of the Project. Additional construction will be required to permit the flow of Prudhoe Bay gas.

In 1980, the Alaskan Partnership and the three major Prudhoe Bay gas producers (the "Producers"), Atlantic Richfield Company, Exxon Corporation and The Standard Oil Company (Ohio), entered into an agreement (the "Cooperative Agreement") which established a jointly funded, jointly managed undertaking for the design, engineering and construction planning of the Alaska segment of the pipeline and the gas conditioning plant necessary to prepare the gas for pipeline transmission. Under this Cooperative Agreement, the Alaskan Partnership and the Producers are making capital contributions on a 50/50 basis until design and engineering work for the Alaska segment of the pipeline and the conditioning plant have been completed. The State of Alaska, a signatory to the Cooperative Agreement, is initially monitoring the design and engineering effort as an observer, but the State may elect to participate financially at a later date and then assume full participation in management of the design and engineering effort.

Capital Costs
The estimated capital costs for the Project, stated in 1980 dollars as required by FERC and excluding AFUDC, are as follows: approximately $10.8 billion for the pipeline facilities in the Alaska segment and approximately $3.6 billion for the gas conditioning plant; approximately $5.8 billion (U.S.) for the Canadian segment; and approximately $2.8 billion for the Northern Border and Western Leg segments. These estimates include contingencies and allowances for abnormal events which vary for the conditioning plant and each major pipeline segment. Inflation and AFUDC during the period of construction will, of course, significantly increase the final cost of the Project. It is anticipated that total cash requirements for all segments of the Project, projected to the dates of actual expenditure and including capitalized interest, will fall in the range of $39 billion to $48 billion.

Of the estimated capital costs for the delivery system necessary to deliver Prudhoe Bay gas to markets in the lower 48 states, as set forth above, commitments for approximately $2.5 billion in 1980 dollars have been made and financing has been secured.

Financing of the Alaska Segment and Conditioning Plant
In May 1981, the Alaskan Partnership reported to the United States Department of Energy that it had reached agreement with the Producers on a conceptual approach to a private financing of the Alaska segment of the pipeline and the conditioning plant for presentation to the financial community. The agreement provided that the conditioning plant and the pipeline would be financed as one project and that the Producers would be given a minority ownership.

On the basis of the agreement reached by the Alaskan Partnership and the Producers, the first formal presentation of a financing plan was made in May 1981 to four major U.S. commercial bank lenders—Bank of America, N.T. & S.A.; The Chase Manhattan Bank, N.A.; Citibank, N.A., and Morgan Guaranty Trust Company of New York.

This plan embodied the following concepts: (a) the debt/equity ratio for all capital investment would be 75:25; (b) the investment limits of all participating companies would be defined from the outset; (c) the Alaskan Partnership and the Producers would be responsible for arranging funding of 70% and 30% of the Alaska segment of the Project, respectively; (d) debt funds would be sought on a project credit basis with a pre-committed completion assurance pool of funds established to provide assurance to investors that construction of the facilities would be completed; and (e) that each company's participation would be subject to

various conditions including, but not limited to, the conditioning plant being included as part of the Alaska segment of the Project, the Project being deemed economically viable and the receipt of all necessary governmental approvals and authorizations acceptable to the participants.

In August 1981, the four-bank coordinating group advised the Alaskan Partnership of the results of its preliminary assessment of the financing concepts, and the general availability of debt funds available to the Alaska segment of the Project. These banks also suggested certain modifications to the financing plan which the Alaskan Partnership and the Producers might consider. The banks preliminarily concluded, subject to various conditions and caveats, that:

(a) the Alaska segment of the Project can be privately financed without government guarantees or participation;

(b) under current market conditions there would be available on a world-wide basis up to $18 billion as debt for the Alaska segment of the Project;

(c) after completion, and when satisfactory tariff and tracking arrangements become effective, the tariff will provide adequate assurances of debt service;

(d) the completion pool of funds concept would not be perceived by lenders generally to be acceptable, in and of itself, and a modified financing proposal should be considered which would provide credit support for the majority of the debt during the pre-completion phase, by the sponsors of the Alaskan Partnership, the Producers or other creditworthy parties. The banks concluded that if the required credit support could be arranged, such a modified plan might well provide the basis for private sector financing of the Alaska segment of the Project.

Since the passage of the waiver package in December 1981 (see "Status of Certain Key Regulatory Approvals"), discussions among the Alaskan Partnership, the Producers and the four major banks have continued on a regular basis with the objective of determining the final structure of a private financing plan. Energy continues to believe that agreement will be reached on a definitive financing plan.

Incentive Rate of Return

The "incentive rate of return" on equity investment concept, which does not include the gas conditioning plant but will apply separately to the Alaska and Northern Border segments, is designed to provide an incentive for minimizing construction costs by establishing variable rates of return on equity. The rate of return would decrease if construction cost overruns occurred and increase if construction costs were lower than estimated. For example, the order provides for a return on equity of 17.5% for the Alaska segment if it is completed at its final preconstruction cost estimate, against a return on equity of 12.75% if there is a 100% cost overrun. In recognition of unanticipated construction risks, FERC may in its final Certificate provide for a 17.5% rate of return even if the actual costs exceed the projected costs. This would be accomplished by an adjustment in the final Certificate of the ratio of the actual cost to the projected cost at greater than one to one. The Alaskan Partnership has applied for a ratio of 1.267 to one and is awaiting FERC action on such application.

The final Certificate for the early construction phases of the Northern Border segment provides that a rate of return on equity of 15% will be earned if the ratio of actual construction costs to estimated construction costs is equal to 1.0758 to one, with higher returns to be earned if the ratio is less than 1.0758 to one and lower returns to be earned if the ratio is greater than 1.0758 to one.

In determining the final cost performance of each segment, which establishes the respective rates of return on equity, FERC has provided for inflation adjustments and adjustments for the cost of certain unanticipated or mandated changes after the final cost estimates are approved.

Status of Certain Key Regulatory Approvals

In December 1981, Congress approved, and President Reagan signed, a waiver of existing law designed to help achieve private financing for the Project. This waiver permits equity participation in the Project by the Producers, includes the necessary North Slope gas conditioning plant as an integral part of the Project and authorizes FERC to approve a tariff which would provide adequate assurance of debt repayment and to expedite issuance of remaining FERC approvals. In that connection, FERC has scheduled a conference in early 1982 to receive a report on the status of efforts to obtain financing for the Alaska segment and conditioning plant, to discuss the matters remaining for FERC consideration and to discuss procedures which FERC could use to expedite consideration of these matters.

In January 1982, various parties, including 24 Congressmen, five states and several consumer groups, filed suit in Federal Appeals Court challenging Congressional approval of the waiver package mentioned above and seeking to reverse such approval. While this suit may cause a potential delay, Energy's management believes the suit is without merit and will be dismissed.

Energy's Investment in the Project

Alaska Segment—

Summary financial information of the Alaskan Partnership and Cooperative Agreement as of December 31, 1981, follows:

	(Millions of Dollars)
Natural gas transmission plant and conditioning plant under construction	$586.6
Working capital	(9.8)
Partners' and Producers' equity	$576.8

Natural gas transmission plant and conditioning plant under construction, shown above, consists primarily of costs associated with research, design and engineering, filings with regulatory authorities and, for the Alaskan Partnership, allowance for equity funds capitalized at an annual rate of 14%, as authorized by FERC.

Energy's investment in the Alaskan Partnership was approximately $62.2 million as of December 31, 1981, including $21.1 million of allowance for equity funds capitalized. It is anticipated that Energy's investment in the Alaskan Partnership will increase in 1982 by approximately $23.4 million, of which approximately $13.6 million will be for capital expenditures and approximately $9.8 million will be allowance for equity funds capitalized.

Since formation of the Alaskan Partnership, Pipeline has provided services to the Alaskan Partnership and has been reimbursed at its cost. Such amounts for 1981, 1980 and 1979 totaled approximately $2.3 million, $2 million and $2.9 million, respectively.

While Energy has not made final commitments on the timing or the total amount of funds it will invest in the Alaska segment of the Project, Energy presently intends to maximize its equity investment in the Alaskan Partnership to the extent prudent, and anticipates that such investment will be approximately $500 million (excluding AFUDC).

Energy currently estimates that if the Alaska segment of the Project were to be abandoned in the near future for any reason, Energy's portion of the funds required to permit an orderly cessation of operations would not exceed $3 million. This amount will, of course, increase over the course of time as more commitments are undertaken with respect to the Alaska segment. In such case, recovery of the Project costs would be dependent upon receipt of required governmental approvals. However, FERC has stated that it is not contemplated that sponsors could recover their investment through charges to existing customers if the Project were abandoned, reaffirming that it believed the President's Decision did not contemplate such charges. If such recovery were not approved, Energy's investment in the Alaska segment, net of tax benefits, would be written off.

Northern Border Segment—

Summary financial information of Northern Border as of December 31, 1981, follows:

	(Millions of Dollars)
Natural gas transmission plant under construction	$965.1
Working capital	(4.4)
Unamortized issuance costs of debt	4.8
Long-term debt	(538.9)
Partners' equity	$426.6

Energy's investment in all phases of Northern Border was approximately $52.3 million as of December 31, 1981, including $4.7 million of allowance for equity funds capitalized. It is anticipated that Energy's investment in Northern Border will increase in 1982 by approximately $11.7 million, of which approximately $3.5 million will be for capital expenditures, approximately $6.8 million will be allowance for equity funds capitalized and approximately $1.4 million will be for equity earnings from operations, retained in Northern Border. Energy anticipates that its cash investment in all phases of the Northern Border segment will approximate $108 million.

The Northern Border segment to be constructed for transportation of Canadian gas volumes will cost approximately $1.3 billion projected to the date of actual expenditure, including capitalized interest. Energy's percentage interest in Northern Border is 12.25%. Energy anticipates a cash investment in phase one of the Northern Border segment of approximately $49 million. In December 1980, the debt and equity financing agreements for the Northern Border segment were completed. These agreements include a bank credit agreement that provides for loans aggregating up to $1,055 million upon satisfaction of various conditions to lending and an equity commitment agreement among the partners. In addition, if Northern Border were for any reason to have insufficient funds available from its lending banks and other sources to pay all costs of constructing and placing this portion of the Project in service, the five Northern Border sponsors, including Energy, would be committed (severally on the basis of their respective ownership interests) to supply Northern Border with the amount needed and, if the Northern Border segment were not to be placed in service by 1984, to purchase, prior to 1985, the business and assets of Northern Border at a price equal to the cost thereof to Northern Border. At December 31, 1981, Northern Border had borrowed $538.9 million under its bank credit agreement.

Current estimates are that gas deliveries under the Project will commence in 1987, provided that there are no untimely delays in arranging financing for the Project, in the receipt of the remaining necessary governmental and regulatory approvals, or in the operational date of the gas conditioning plant and that pending litigation is expeditiously and favorably resolved. Pursuant to the waiver of law approved by Congress, FERC, in consultation with the Office of the Federal Inspector, is responsible for establishing the target completion date for the Project. The ultimate success of the Project is dependent upon final governmental and regulatory authorizations and cost approvals, satisfactory gas purchase, sale and transportation contracts, adequate financing and successful completion of construction. Management believes the Project is in the national interest and will be successfully completed.

(3) Rate Matters

1981 General Rate Increase

On March 31, 1981, Pipeline filed with FERC a general rate increase application seeking authorization to increase its rates by approximately $115.7 million annually to cover increased costs associated with special overriding royalties, gas supply projects, higher operating and maintenance expenses, the effect of decreased sales volumes and higher costs of capital. Such rates were placed into effect on October 1, 1981, subject to refund.

Pursuant to an agreement-in-principle reached by the parties involved in the 1981 general rate increase proceeding, Pipeline is collecting the filed rates during the twelve-

month period that commenced October 1, 1981. Pipeline has agreed to refund amounts collected that exceed its actual costs of providing natural gas service, including a return on rate base, during such twelve-month period. Management of Pipeline believes that Pipeline ultimately will have no refund obligations related to the overall rate level. Therefore, no provision for possible refunds is reflected in the accompanying financial statements.

Several issues related to the 1981 general rate increase, however, have not been settled. In one of these issues, the FERC staff is contesting the amounts of special overriding royalties related to Pipeline's gas production from wells drilled before 1973 that are includable in rates at its cost of service. This issue is scheduled for hearing before FERC in 1982. Management of Pipeline believes that the resolution of this matter will not have a material adverse financial impact on Pipeline. Also see "Special Overriding Royalty Cases" below. The other unsettled issues relate to the allocation of the rate increase to various classes of service.

Special Overriding Royalty Cases

Approximately 75% of Pipeline's San Juan Basin natural gas leasehold production is obtained under leases which include special overriding royalty provisions with escalation formulas which generally require periodic price redeterminations. Pursuant to previously negotiated settlement agreements, such special overriding royalty payments for gas produced from pre-1973 wells are included in Pipeline's gas sales rates. These payments have been determined to be subject to FERC jurisdiction by FERC Orders issued September 25, 1980 and December 18, 1980. Litigation regarding the issue of FERC jurisdiction over the prices paid to special overriding royalty owners is presently pending in the courts. Pending the outcome of such litigation, FERC has initiated proceedings to determine the regulated prices Pipeline should pay the special overriding royalty owners in the future and whether refunds are due for past periods. At this time, it is impossible to determine the results of such litigation and FERC proceedings, but, if it is ultimately determined that FERC has jurisdiction, the royalty owners could be required to repay Pipeline for the difference between the reduced royalty rates and the royalty payments received by such royalty owners. In such event, Pipeline would be obligated to refund to its customers amounts applicable to Pipeline's production from wells drilled prior to 1973, but may be permitted, subject to FERC approval, to retain the payments applicable to Pipeline's production from wells drilled thereafter, since, pursuant to FERC Orders, Pipeline has priced such production at the applicable nationwide or Natural Gas Policy Act of 1978 ("NGPA") rates in lieu of actual cost of service.

The proper pricing of Pipeline's gas leasehold production may also be affected by the decision of the Fifth Circuit Court of Appeals in *Mid-Louisiana Gas Company vs. FERC,* issued December 23, 1981. According to that decision, all pipeline gas production must be priced pursuant to the NGPA. Assuming this decision is not amended or reversed after further appeal, the cost-of-service rate treatment applied to Pipeline's gas production from pre-1973 wells could be withdrawn, and Pipeline would be required to value this production at the applicable NGPA price. As an initial assessment, management of Pipeline believes that the applicable NGPA price would be less than the cost of production, including the special overriding royalty payments discussed above. This potential problem should not arise if the special overriding royalty payments are determined to be subject to FERC jurisdiction, thereby subjecting them to NGPA pricing limitations. However, if the special overriding royalty payments are ruled to be nonjurisdictional, the decision in *Mid-Louisiana* creates the possibility that Pipeline will not be allowed by FERC to collect from its customers amounts sufficient to meet the payment demands of the special overriding royalty owners under their interpretations of the lease contracts. Under such conditions, Pipeline believes it could obtain special relief from FERC, or obtain an alternative form of remedy to allow it to recover its cost of service.

(4) Capital Stock

Common Stock Distributions

A 100% common stock distribution was effected on June 8, 1979. Accordingly, common shares outstanding doubled on that date and "Additional paid-in capital" was charged the $1 par value for each additional share issued. A three-for-two common stock distribution was effected on September 12, 1980. Therefore, common shares increased again by approximately 50% on that date and "Additional paid-in capital" was charged the $1 par value for each additional share issued. In the accompanying financial statements, all applicable numbers of common shares and amounts per common share have been adjusted to reflect these common stock distributions.

Change in Authorized Shares

At the Annual Meeting of Stockholders held April 28, 1981, the stockholders voted to amend Energy's Articles of Incorporation, changing the capitalization of Energy to provide for an increase from 40,000,000 to 80,000,000 in authorized shares of common stock, $1 par value.

Dividend Reinvestment and Stock Purchase Plan

Energy has established a Dividend Reinvestment and Stock Purchase Plan, which provides holders of record of Energy's common and/or preference stock a method of investing cash dividends and/or optional cash payments in common stock of Energy at a discount, without the payment of any brokerage commission, service charge or other expense. Shares purchased by the participants are made available at a 5% discount from market value, as further set out in the plan. Energy has the option to issue new common shares or purchase such shares on the open market.

Preference Stock of Energy

Each share of the preference stock is convertible into common stock of Energy at any time at the rate of .81522 shares of common stock for each share of the preference stock (equivalent to a conversion price of $30.6667 per share), subject to adjustment under certain conditions. The preference stock is redeemable at any time at the option of Energy, in whole or in part, initially at a redemption price of $27.13 per share and thereafter at declining prices, plus dividends accumulated to the redemption date. Dividends are payable quarterly and commenced October 1, 1980.

At December 31, 1981, the total involuntary liquidation preference of the outstanding preference stock of Energy was approximately $75 million and exceeded the total par value by approximately $72 million. Such excess does not impose any restriction on retained earnings.

Preferred Stock of Energy

Energy's authorized capital included 10,000,000 shares of preferred stock, $1 par value and issuable in series, at December 31, 1981. None of the authorized preferred stock has been issued to date.

Preferred Stock of Pipeline

The preferred shares of Pipeline are redeemable for sinking fund requirements at $25 per share, beginning on January 1, 1981 for the $2.50 series and on July 1, 1984 for the $2.36 series. Additionally, Pipeline may, at any time, redeem all or part of the preferred stock at $25 per share, plus specified premiums and accrued dividends, subject to certain refunding restrictions. If dividends on the preferred shares become in arrears in an aggregate amount equal to six quarterly dividends, holders of the outstanding preferred shares of all series will have the right, voting as a class, to elect two members of Pipeline's Board of Directors and such right will continue until all cumulative dividends in arrears have been paid.

Sinking fund requirements for both outstanding series, for each of the five years subsequent to December 31, 1981, are as follows:

Year Ending December 31,	(Thousands of Dollars)
1982	$ —
1983	1,230
1984	3,600
1985	3,600
1986	3,600

At December 31, 1981, the total involuntary liquidation preference of the outstanding preferred shares of Pipeline was $52,480,000 and exceeded the total par value by $50,380,800. Such excess does not impose any restriction on retained earnings.

(5) Long-Term Debt

Sinking Fund Debentures and First Mortgage Pipe Line Bonds

Under the terms of Pipeline's indentures for its sinking fund debentures, restrictions exist which preclude the issuance of additional mortgage bonds. The indentures for both the first mortgage pipe line bonds and the sinking fund debentures contain provisions for the acceleration of sinking fund payments under certain conditions related to potential future exhaustion of Pipeline's available gas supply.

Under the terms of the Company's mortgage indentures and secured notes, substantially all property, plant and equipment, major gas purchase and sales contracts and certain gas exchange and operating agreements are pledged as collateral.

9% Convertible Subordinated Debentures

The debentures are convertible into 41.2371 shares of the Company's common stock for each $1,000 principal amount of the converted debentures (equivalent to $24.25 per share), or, prior to July 15, 1988, into an equal principal amount of 16½% nonconvertible subordinated debentures, due July 15, 1996.

Variable-Interest-Rate Bank Term-Loans

On September 29, 1981, Pipeline converted $90 million of its short-term borrowings into unsecured term-loans with a group of nine banks. The interest rate during the term of the loans will be equal to approximately 108% of the banks' prime interest rates.

Maturities of Long-Term Debt

Sinking fund requirements and other maturities of long-term debt, for each of the five years subsequent to December 31, 1981, are as follows:

Year Ending December 31,	(Thousands of Dollars)
1982	$39,434
1983	43,822
1984	41,812
1985	36,104
1986	35,313

(6) Retained Earnings

Restrictions

Pipeline's debt indentures, as well as the certificates of designation which authorized Pipeline's preferred stock, contain provisions which impose restrictions on retained earnings regarding the payment of dividends on Pipeline's common stock. Under the most restrictive of these provisions, at December 31, 1981 approximately $17.2 million of consolidated retained earnings was restricted as to the payment of dividends on Energy's common stock.

Undistributed Equity Earnings in Affiliates

At December 31, 1981 and 1980, retained earnings included approximately $30.5 million and $16.8 million, respectively, of undistributed earnings from 50% or less owned affiliates that are accounted for by the equity method of accounting.

(7) Line-of-Credit Arrangements

Through a number of banks, the Company had unsecured line-of-credit arrangements and other short-term credit facilities which aggregated $597 million at December 31, 1981 and $430 million at December 31, 1980, against which $154.8 million was drawn at December 31, 1981 and $39.3 million was drawn at December 31, 1980. In addition, the Company had incurred $69.7 million of short-term debt on an "as available" basis at December 31, 1981, which is not a part of the line-of-credit arrangements.

Interest rates for the $597 million line-of-credit arrangements vary primarily with bank prime interest rates. The Company has agreed to commitments on the various lines such as fees of ½% on available amounts or maintaining average annual compensating bank balances equal to 10% of credit availability plus 10% of outstanding loan balances. Additionally, $250 million of the lines-of-credit may be converted into term-loans, with various repayment dates through December 15, 1989.

Pipeline has a $25 million bankers acceptance facility (included in the $597 million discussed above). This bankers acceptance facility is supported by a $25 million revolving credit arrangement. Interest rates on the bankers acceptance facility vary with changes in bankers acceptance interest rates.

The Company has a total of $157 million (included in the $597 million discussed above) in available credit lines which contain compensating bank balance features. No legal restrictions exist prohibiting the withdrawal of funds used to meet these requirements. The average annual compensating balance required, based upon credit availability and borrowings outstanding at December 31, 1981, was approximately $20.4 million.

(8) Income Taxes

The provision for income taxes reflected in the consolidated statement of income consists of the following components:

	Year Ended December 31,		
	1981	1980	1979
	(Thousands of Dollars)		
Included in Operating Expenses:			
Currently payable—			
Federal	**$(22,748)**	$27,135	$12,756
State	**(1,411)**	2,163	1,837
Subtotal	**(24,159)**	29,298	14,593
Deferred Federal and state—			
Current	**17,270**	(20,695)	(9,955)
Noncurrent	**23,460**	25,520	23,790
Subtotal	**40,730**	4,825	13,835
Total	**$ 16,571**	$34,123	$28,428

The 1981 current Federal and state income tax benefit reflects the carryback of the Company's 1981 tax net operating loss and the carryback of investment tax credits.

Deferred tax expense results from timing differences in the recognition of revenues and expenses for tax and financial reporting purposes. The sources of these differences and the tax effect of each are as follows:

	Year Ended December 31,		
	1981	1980	1979
	(Thousands of Dollars)		
Current:			
Gas purchase costs, deferred (expensed) in the financial statements and deducted for tax reporting purposes as paid	**$23,654**	$(23,236)	$ 4,149
Unrecovered special overriding royalties, expensed in the financial statements and deferred for tax reporting purposes	**(3,188)**	(890)	(7,386)
Gas sales rate adjustments, recognized currently for tax reporting purposes and reserved for in the financial statements	**2,965**	5,297	(6,690)
Investment tax credit carryforwards, recognized currently in the financial statements and carried forward for tax reporting purposes	**(7,981)**	—	—
Other	**1,820**	(1,866)	(28)
Noncurrent:			
Liberalized tax depreciation in excess of book depreciation	**13,006**	10,652	12,875
Intangible drilling and development costs, capitalized in the financial statements and deducted currently for tax reporting purposes	**8,472**	7,098	4,399
Distributive share of tax loss related to the Alaska Highway Pipeline Project, capitalized in the financial statements and deducted currently for tax reporting purposes	**2,400**	850	3,333
Allowance for borrowed funds used during construction, capitalized in the financial statements and deducted currently for tax reporting purposes	**—**	2,232	1,060
Other	**(418)**	4,688	2,123
Total	**$40,730**	$ 4,825	$13,835

The total provision for income taxes shown above is less than the amount which would be computed by applying the statutory Federal income tax rate to income before income taxes and preferred stock dividend requirements of Pipeline.

The table below summarizes the major reasons for such difference:

	Year Ended December 31,		
	1981	1980	1979
	(Thousands of Dollars)		
Tax expense computed at statutory Federal rate	**$42,270**	$42,993	$34,515
Increase (decrease) in tax provision resulting from:			
Investment tax credit recognized currently	**(24,301)**	(8,567)	(6,315)
Allowance for equity funds capitalized during engineering, design and construction on the Alaska Highway Pipeline Project, which does not constitute taxable income	**(5,474)**	(2,985)	(1,929)
Amortization of tax timing differences for which deferred taxes were not previously provided	**2,105**	2,097	2,056
Other	**1,971**	585	101
Actual tax expense	**$16,571**	$34,123	$28,428

As a result of the Company's capital expenditure program, at December 31, 1981 the Company had approximately $8.4 million in investment tax credit carryforwards available to offset income taxes payable in future periods. Such carryforwards will expire in 1996, if not previously utilized. The benefit of these investment tax credit carryforwards has been recognized currently for financial reporting purposes.

(9) Sales to Major Customers

During the periods presented, more than 10% of the Company's consolidated operating revenues was generated from sales (primarily gas sales) to each of the following customers:

	Year Ended December 31,		
	1981	1980	1979
	(Thousands of Dollars)		
Sales to:			
Northwest Natural Gas Company	**$ 266,698**	$ 251,195	$ 217,180
Washington Natural Gas Company	**227,046**	213,910	173,582
Colorado Interstate Gas Company	**152,204**	135,928	99,610
Cascade Natural Gas Corporation	**150,761**	138,583	114,103
Other operating revenues	**602,100**	583,816	515,057
Consolidated operating revenues	**$1,398,809**	$1,323,432	$1,119,532

(10) Executive Benefit Plans

The Company's Executive Incentive Plan provides for biennial awards of performance share units to certain of the Company's executives and key employees. The plan entitles recipients to earn, over a four-year period from each award date, common stock of Energy or cash, or a combination thereof, based on the Company's cumulative earnings performance during each such period. Awards earned are paid at the end of each four-year period. The 1976 awards were paid in February 1980 and the 1978 awards were paid in February 1982. Under the plan, at December 31, 1981, there were 299,337 units outstanding. Accrued compensation expenses related to the plan were approximately $.5 million, $3.5 million and $1.5 million for 1981, 1980 and 1979, respectively.

The Company has an unfunded supplemental retirement plan for certain key executives. Participation in this plan is determined by the Board of Directors. Participants, or their surviving spouses, if applicable, are eligible to receive monthly benefits upon retirement or disability, based on levels of compensation prior to such retirement or disability and considering the number of years of each participant's industry or related service, as determined by the Board of Directors. Benefits payable under the plan are reduced by payments received under the Company's Employees Retirement Income Plan or similar plans of previous employers. Costs accrued for 1981, 1980 and 1979 were approximately $1.7 million, $.9 million and $.7 million, respectively.

(11) Employee Benefit Plans

The Company's Employees Retirement Income Plan covers employees who have completed one year of service with the Company. The plan provides retirement benefits, at no cost to the employee, on the basis of length of service and rates of compensation prior to retirement. The plan provides for full vesting after ten years of service or attainment of age 55. Costs accrued for 1981, 1980 and 1979 were approximately $5.4 million, $4.3 million and $3.1 million, respectively. Such accrued costs are being funded currently. Accumulated plan benefits and plan net assets as of the most recent actuarial determination date are presented below:

	December 31, 1980
	(Thousands of Dollars)
Actuarial present value of accumulated plan benefits:	
Vested	$17,232
Nonvested	2,671
Total	$19,903
Net assets available for benefits	$22,862

The actuarial cost method applied to determine the contribution from Energy to currently fund the plan is the Entry Age Normal Cost Method with Frozen Unfunded Supplemental Present Value. The weighted average assumed rate of return used in determining the actuarial present value of accumulated plan benefits above was 6%, compounded annually. Unfunded past service costs at December 31, 1980 of $9.7 million are being funded over a 20-year period ending December 31, 1993.

The Company also maintains an Employees Savings Plan, an Employee Stock Ownership Plan and a Bonus Employee Stock Ownership Plan ("BESOP"), which are made available to all employees after completion of one year of service with the Company. Costs accrued for these three plans for 1981, 1980 and 1979 were $2.3 million, $1.6 million and $1.3 million, respectively.

The Energy common shares for the BESOP were purchased in 1979 by the Trustee for $6,573,000 from the proceeds of a loan of the same amount from Energy, evidenced by a promissory note, payable annually through December 31, 1998, and bearing interest at variable rates during the 20-year term of the loan. The obligation of the Trustee to Energy is reflected in the accompanying consolidated balance sheet as a reduction in common stockholders' equity. Such equity is being reinstated as the loan is repaid.

(12) Commitments and Contingencies

1982 Capital Expenditures

The total consolidated capital expenditures of the Company for 1982 are estimated to be approximately $224.3 million, including approximately $17.1 million for the Alaska Highway Pipeline Project.

New Office Building

An office building, which will serve as the Company's headquarters, is presently under construction in Salt Lake City, Utah. The estimated construction cost of the facility is approximately $38 million including capitalized interest charges. Building construction is scheduled for completion during the second quarter of 1982. The facility has been financed through a leveraged lease agreement with a limited

partnership, as lessor, and with Pipeline, as lessee. Under the agreement, the partnership has provided construction financing and is obligated to arrange long-term financing for the building.

On January 28, 1982, the partnership arranged with lenders a long-term debt commitment for the building. Such arrangement included, among other things, that the partnership must have the equity contributions backed with a form of irrevocable credit by June 1, 1982 or a subsidiary of the Company will have the option to arrange for the equity commitments, or to buy back the obligations of the partnership and terminate the transaction.

Recoverability of Investment in Additional Pipeline Facilities

Pipeline's facilities have recently been expanded to permit the importation of additional natural gas volumes from Alberta, Canada. Pipeline has agreed with FERC to depreciate such facilities over a twelve-year period. The term of the National Energy Board ("NEB") export license is for an approximate seven-year period. The extension of the term depends on the future availability of Canadian or other gas volumes. To the extent that such additional gas volumes do not become available, or if Pipeline cannot demonstrate a future use for such facilities, Pipeline may not be permitted to recover, through gas sales rates, the depreciation of these facilities over the remaining five-year period after the expiration of the present NEB export license. The net book value of the facilities at the end of the export license period is estimated to be approximately $52.4 million. Management of Pipeline believes, however, that it will be able to demonstrate a future use for such facilities and will be permitted full recovery of the cost of these facilities through Pipeline's gas sales rates.

Coal Sales Commitment

A wholly owned subsidiary of Energy has entered into a long-term contract with a third party for the delivery of from 400,000 to 500,000 tons of coal per year, starting in 1983. This contract was supported by a contract with a second subsidiary for the coal from undeveloped Utah properties acquired in 1980 by the second subsidiary. A third subsidiary of Energy was committed under the contract to supply any coal volumes not able to be supplied from the Utah properties for a period up to eleven years. In May 1981, it was concluded, based on information not previously available, that the Utah properties could not be economically developed at required production levels to satisfy the contract. Negotiations are under way with the contracting party seeking a resolution to this matter through several alternative courses of action. Management believes that the matter can be resolved without a material adverse financial impact on the Company.

Legal Matters

Pipeline is a party to three lawsuits that are related to the construction of its facilities to permit the importation of additional natural gas volumes from Alberta, Canada. The plaintiffs essentially claim that Pipeline's inspection procedures were too strict through the term of the construction and thereby caused the contractors to incur additional costs and suffer other damages. Considering presently available facts, management believes that Pipeline has meritorious defenses to the claims made by the plaintiffs. However, if the plaintiffs prevail in one or more of the suits, or if settlement is effected, there would be no adverse impact on income of future periods, since such costs would be capitalized as additional gas transmission property.

Pipeline is also a party to a lawsuit which concerns the alleged miscalculation of amounts previously applied to a carried interest in certain gas production properties. At issue is the determination of the payout date and reversion of working interests to the plaintiff. Management believes that the resolution of this matter will not have a material adverse financial impact on Pipeline.

The Company is a party to various other lawsuits. Based on presently available facts, as well as available defenses, management believes that these suits are not material to the operations or financial condition of the Company as a whole.

(13) Leases

The Company does not conduct any significant operations with leased facilities. The Company's leasing arrangements, exclusive of mineral leases, include primarily premise and equipment leases that are classified as operating leases. FERC permits recovery, through Pipeline's current gas sales rates, of the rental payments made under its lease arrangements. If leases entered into by the Company which qualify as capital leases were required to be capitalized, the effect on assets, liabilities and expenses for the periods presented would not be significant.

(14) Related Party Transactions

During 1981, Energy invested, through a wholly owned subsidiary, $20 million in certain producing oil and gas properties. A nonconsolidated affiliate of the Company also invested the same amount in the properties. Energy exercises significant management control over the affiliate and directly owns approximately 17.5% of that company's common stock.

During the periods presented, the Company has entered into various other transactions with certain related parties, the amounts of which were not significant. The Company believes that the terms of all related party transactions were as favorable as could have been obtained from unrelated parties.

(15) Historical Oil and Gas Data

The Company's oil and gas operations are conducted by Pipeline, by an oil and gas exploration and development subsidiary of Energy, Northwest Exploration Company ("Exploration") and through certain joint venture arrangements. The majority of the Company's total oil and gas reserves and production is related to Pipeline's gas reserves.

Pipeline's predominant activity is the interstate transmission and sale of natural gas, and it is therefore subject to regulation by FERC. Under FERC guidelines, Pipeline accounts for its entire gas development and production activities under the successful-efforts accounting method. Oil and gas activities, other than Pipeline, are being accounted for under the full-cost method of accounting.

The following schedule presents the Company's capitalized oil and gas property costs at the dates indicated:

	December 31,		
	1981	1980	1979
	(Thousands of Dollars)		
Proved properties	**$176,124**	$125,418	$ 99,272
Unproved properties	**24,201**	15,371	11,362
Total	**200,325**	140,789	110,634
Accumulated depreciation, depletion and amortization	**(33,195)**	(30,511)	(27,463)
Net capitalized costs	**$167,130**	$110,278	$ 83,171

DD&A expense applicable to oil and gas operations of $4,573,000 in 1981, $3,940,000 in 1980 and $3,855,000 in 1979 was charged to income. This resulted in a consolidated DD&A rate of 12.7¢, 9.4¢ and 8.8¢ per equivalent thousand cubic feet of gas produced in 1981, 1980 and 1979, respectively.

The following tabulation details the costs incurred in 1981, 1980 and 1979 in the Company's oil and gas operations:

	Year Ended December 31,		
	1981	1980	1979
	(Thousands of Dollars)		
Property acquisition costs	**$25,451**	$ 5,704	$3,008
Exploration costs	**$12,620**	$ 9,185	$5,711
Development costs	**$23,365**	$19,549	$8,731
Production costs	**$ 7,580**	$ 6,838	$5,183

The following schedule presents an analysis of changes in the Company's proved oil and gas reserves during 1981, 1980 and 1979, all of which are domestic reserves:

	Unaudited					
	(Volumes in Millions of Barrels of Oil and Billions of Cubic Feet of Gas)					
	1981		1980		1979	
	Oil	Gas	Oil	Gas	Oil	Gas
Proved Developed and Undeveloped Reserves:						
Beginning of year	**1.3**	**1,293**	1.8	1,310	1.3	945
Revision of previous estimates	**1.3**	**(258)**	(.3)	(23)	.2	390
Extensions, discoveries and other additions	**4.4**	**73**	—	47	.5	17
Purchases of minerals-in-place	**2.1**	**1**	—	—	—	—
Production	**(.2)**	**(35)**	(.2)	(41)	(.2)	(42)
End of year	**8.9**	**1,074**	1.3	1,293	1.8	1,310
Proved Developed Reserves:						
Beginning of year	**.7**	**1,134**	1.5	1,164	1.1	796
End of year	**5.7**	**911**	.7	1,134	1.5	1,164

The reserve estimates are reviewed and revised at least annually based upon updated geological and production data. Independent consulting engineer estimates for the reserve information related to Pipeline's and Exploration's gas reserves are in substantial agreement with the Company's reserve estimates used in the reserve table above.

It should be noted that difficulties and uncertainties involved in estimating proved oil and gas reserves make comparisons between companies extremely difficult. Estimation of reserve quantities is subject to wide fluctuations because it is dependent upon judgmental interpretation of geological and geophysical data.

Reserve Recognition Accounting data is not presented herein because the Company meets the prescribed tests for exemption from disclosure.

Auditors' Report

To the Stockholders and Board of
Directors of Northwest Energy Company:

We have examined the consolidated balance sheet of Northwest Energy Company (a Utah corporation) and subsidiaries as of December 31, 1981 and 1980, and the related consolidated statements of income, capitalization, common stockholders' equity and changes in financial position for each of the three years in the period ended December 31, 1981. Our examinations were made in accordance with generally accepted auditing standards and, accordingly, included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances.

In our opinion, the financial statements referred to above present fairly the financial position of Northwest Energy Company and subsidiaries as of December 31, 1981 and 1980, and the results of their operations and the changes in their financial position for each of the three years in the period ended December 31, 1981, in conformity with generally accepted accounting principles applied on a consistent basis.

Arthur Andersen & Co.

Salt Lake City, Utah
February 11, 1982

Selected Quarterly Financial Data (Unaudited)

	Quarter of 1981				Quarter of 1980			
	First	Second	Third	Fourth	First	Second	Third	Fourth
(Dollars in Thousands, Except Per Share Amounts)								
Operating revenues	**$428,700**	**$287,178**	**$224,780**	**$458,151**	$431,528	$283,770	$212,035	$396,099
Operating expenses, including income taxes	**397,447**	**266,158**	**206,238**	**418,890**	409,596	266,138	199,996	376,957
	31,253	**21,020**	**18,542**	**39,261**	21,932	17,632	12,039	19,142
Interest charges and other income, net	**6,662**	**5,257**	**6,171**	**21,845**	3,837	6,891	4,443	1,499
Net income	**24,591**	**15,763**	**12,371**	**17,416**	18,095	10,741	7,596	17,643
Less—Preference stock dividend requirement	**1,594**	**1,594**	**1,593**	**1,593**	—	—	1,134	1,594
Net income applicable to common stock	**$ 22,997**	**$ 14,169**	**$ 10,778**	**$ 15,823**	$ 18,095	$ 10,741	$ 6,462	$ 16,049
Income per share applicable to common stock and common stock equivalents:								
Primary	**$ 1.43**	**$ .88**	**$ .64**	**$ .91**	$ 1.15	$ .68	$ .41	$ 1.00
Fully diluted	**1.32**	**.84**	**.64**	**.87**	1.13	.67	.40	.95
Weighted average number of common shares and common stock equivalents outstanding, in thousands:								
Primary	**16,052**	**16,121**	**17,435**	**17,891**	15,768	15,853	15,895	15,987
Fully diluted	**18,667**	**18,736**	**20,049**	**20,519**	15,957	16,022	16,064	18,602
Dividends declared per share of common stock	**$ .25**	**$ .30**	**$ .30**	**$ .30**	$ .217	$ .233	$ .25	$ .25
Market value per share of common stock:								
High	**$ 32¼**	**$ 26½**	**$ 24¾**	**$ 25⅜**	$ 26⅞	$ 23¼	$ 29	$ 37⅛
Low	**23**	**21⅜**	**15⅝**	**18¼**	14	16⅛	22⅛	25¼

Note: All amounts per share and weighted average number of shares of common stock reflect a 50% distribution on September 12, 1980.

Northwest Energy Company's common stock is traded on the New York, London and Pacific Stock Exchanges. Market prices are composite quotations from the New York Stock Exchange and Pacific Stock Exchange as reported in *The Wall Street Journal* and adjusted for the effect of stock distributions. As of January 31, 1982, the number of common stockholders of record was 33,847.

Refer to Note 6 of Notes to Consolidated Financial Statements for information on restrictions as to payment of cash dividends on common stock.

Financial Reporting and Changing Prices (Unaudited)

The following supplementary information concerning the effects of changing prices is supplied in accordance with the general concepts set forth in Financial Accounting Standards Board Statement No. 33 ("FAS 33"), as modified to reflect the economic effects imposed on Pipeline by FERC. It should be viewed as an estimate of the effect of inflation, rather than a precise measurement.

Constant dollar amounts presented herein represent historical costs, restated in terms of dollars of equal purchasing power through application of the Consumer Price Index for All Urban Consumers. The restated amounts do not purport to be appraised value, current value or replacement cost of the Company's assets. Current cost amounts presented herein reflect the changes in industry prices of property, plant and equipment since such assets were acquired, and differ from constant dollar amounts to the extent that industry prices have increased more or less rapidly than prices in general.

The current cost of property, plant and equipment represents the estimated cost of replacing existing plant assets and, for Pipeline, was determined by indexing the surviving plant by the Handy-Whitman Index of Public Utility Construction Costs. The provision for depreciation on the constant dollar and current cost amounts of property, plant and equipment was determined by applying the Company's historical straight-line depreciation rates to the indexed plant amounts. Since the Company does not have vintage year information available for accumulated depreciation, the historical cost relationship between property, plant and equipment and the related accumulated depreciation as of the dates reported was the principal method used to estimate the accumulated depreciation on a constant dollar and current cost basis. Due to a refinement in the underlying calculations for accumulated depreciation, certain data previously disclosed for the year ended December 31, 1980 has been restated. The principal impact of this restatement is a reduction in income from continuing operations previously disclosed for 1980 on a current cost basis. The income from continuing operations, comparing 1980 with 1979, on a current cost basis decreased because 1979 was assumed to be the base year for accumulated depreciation calculations and a similar restatement of current cost income from continuing operations for 1979 was not made.

Gas purchases and current gas stored underground have not been restated from their historical cost in nominal dollars because regulation limits the recovery of such amounts to actual costs. For this reason, current gas stored underground is effectively a monetary asset. As prescribed in FAS 33, income taxes were not adjusted.

Under the rate-making prescribed by FERC, to which Pipeline is subject, only the historical cost of property, plant and equipment is recoverable through revenues as depreciation. Therefore, the excess of the cost of plant, stated in terms of constant dollars or current cost, over the historical cost of plant is not presently recoverable in rates as depreciation, and is reflected as a reduction to the net recoverable cost.

Consolidated Statement of Income From Continuing Operations Adjusted for Changing Prices

	Year Ended December 31, 1981	
	Constant Dollar	Current Cost
	(Millions of Average 1981 Dollars)	
Income From Continuing Operations Applicable to Common Stockholders, as reported under conventional historical cost	$ 63.8	$ 63.8
Erosion of Common Stockholders' Equity Because of Changing Prices:		
Cost in excess of the original cost of productive facilities not recoverable in rates as depreciation—		
Reportable as an additional provision for depreciation	41.9	59.0
Reportable as adjustments to net recoverable cost	14.9	(8.0)
	56.8	51.0
Excess of increases in the general level of prices ($135.9 million) in the current year over increases in industry prices ($125.1 million)*	—	10.8
Effect of debt financing	(42.4)	(42.4)
Net erosion of common stockholders' equity	14.4	19.4
Income From Continuing Operations Applicable to Common Stockholders, as adjusted (including the effect of debt financing)	$ 49.4	$ 44.4

*At December 31, 1981, the current cost of property, plant and equipment, net of accumulated depreciation, was $1,782.5 million, and historical cost or net cost recoverable through depreciation was $892.0 million.

Quantity and price information relative to coal reserves for the Company's coal mining operations, as required by Statement of Financial Accounting Standards No. 39, is not presented because such data is insignificant to overall Company operations.

Five-Year Comparison of Selected Supplementary Financial Data Adjusted for the Effects of Changing Prices

(Dollars in Millions, Except Per Share Amounts)

Year Ended December 31,	**1981**	1980	1979	1978	1977
Operating Revenues: Historical cost	**$1,398.8**	$1,323.4	$1,119.5	$ 820.0	$ 773.1
As adjusted*	**1,398.8**	1,460.7	1,402.7	1,143.1	1,160.3
Income From Continuing Operations Applicable to Common Stockholders: Historical cost	**$ 63.8**	$ 51.3	$ 41.3		
As adjusted**—					
Constant dollar*	**49.4**	33.4	27.9		
Current cost*	**44.4**	25.4	28.9		
Income From Continuing Operations Per Common Share (Primary): Historical cost	**$ 3.83**	$ 3.23	$ 3.03		
As adjusted—					
Constant dollar*	**2.93**	2.10	2.05		
Current cost*	**2.63**	1.60	2.12		
Common Stockholders' Investment (Net Assets), at year-end: Historical cost	**$ 352.1**	$ 301.0	$ 257.7		
As adjusted—					
Constant dollar*	**340.7**	317.3	305.4		
Current cost*	**379.9**	354.8	323.0		
General Price Level Changes in Excess of (Less Than) Increases in Industry Prices*	**$ 10.8**	$ (39.5)	$ 3.4		
Effect of Debt Financing*	**$ 42.4**	$ 44.1	$ 46.1		
Return on Average Common Equity: Historical	**18%**	17%	16%		
As adjusted—					
Constant dollar*	**14%**	11%	9%		
Current cost*	**12%**	7%	9%		
Cash Dividends Declared Per Common Share: Historical cost	**$ 1.15**	$ .95	$ .85	$ .783	$ .717
As adjusted*	**1.15**	1.049	1.065	1.092	1.076
Market Price Per Common Share, at year-end: Historical	**$ 20⅞**	$ 31⅞	$ 20⅝	$ 8⅞	$ 12¾
As adjusted*	**20¼**	33⅝	24⅜	11⅞	18⅝
Average Consumer Price Index (1967 = 100)	**272.4**	246.8	217.4	195.4	181.5

*Amounts have been adjusted to reflect average 1981 dollars.

**Adjusted income from continuing operations applicable to common stockholders would be as follows if only the amount reportable as an additional provision for depreciation were deducted from the reported amount of such income:

	Year Ended December 31,		
	1981	1980	1979
Constant dollar*	$21.9	$21.8	$20.3
Current cost*	4.8	4.1	1.7

Operating Statistics

February 1, 1974 Through December 31, 1981

Northwest Energy Company and Subsidiaries

(Dollars in Millions, Except Amounts Per Unit)	1981	1980	1979	1978	1977	1976	1975	1974*
Consolidated Statistics:								
Effective income tax rate	**18%**	37%	38%	37%	43%	42%	42%	36%
Capital expenditures	**$269.0**	$208.0	$ 95.2	$105.1	$ 76.0	$ 36.1	$ 30.5	$ 29.2
Number of employees, end of period	**2,332**	2,034	1,698	1,536	1,313	1,122	1,191	1,024
Total assets, end of period	**$1,538**	$1,074	$ 863	$ 732	$ 649	$ 575	$ 489	$ 406
Pipeline Statistics:								
Proved gas reserves, end of period (BCF)—								
Canadian purchase contracts	**2,535**	2,882	2,775	2,951	3,396	3,616	4,032	4,298
Domestic purchase contracts	**3,685**	3,390	3,324	3,236	3,168	3,245	3,193	3,050
Pipeline leaseholds	**1,013**	1,247	1,286	924	942	1,013	1,156	1,401
	7,233	7,519	7,385	7,111	7,506	7,874	8,381	8,749
Gas supply volumes, purchased and produced (BCF)—								
Canadian purchases	**167**	192	279	249	286	261	262	262
Domestic purchases	**133**	121	120	113	117	108	111	105
Leasehold production	**33**	40	42	40	40	39	37	31
	333	353	441	402	443	408	410	398
Gas sales volumes (BCF)	**322**	332	426	370	400	393	397	383
Operating income	**$141.8**	$119.6	$ 97.5	$ 62.6	$ 62.6	$ 57.4	$ 52.0	$ 33.0
Average gas sales prices per MCF	**$ 3.90**	$ 3.65	$ 2.46	$ 2.10	$ 1.83	$ 1.51	$ 1.15	$ .70
Average extracted liquid product sales price per gallon	**$ .61**	$ .56	$ .38	$ .24	$ .25	$ .24	$ .19	$ .09
Gas purchase prices per MCF—								
Canadian	**$ 4.93**	$ 4.38	$ 2.64	$ 2.21	$ 1.98	$ 1.75	$ 1.20	$ .68
Domestic	**$ 2.16**	$ 1.56	$ 1.20	$ .92	$ .69	$ .47	$ .37	$ .26
Average	**$ 3.71**	$ 3.29	$ 2.20	$ 1.80	$ 1.61	$ 1.38	$ .95	$ .56
Number of employees, end of period	**1,736**	1,642	1,426	1,364	1,151	1,018	1,047	1,024
Total assets, end of period	**$1,322**	$ 960	$ 797	$ 690	$ 576	$ 506	$ 420	$ 393
Oil and Gas Statistics:								
Net acreage under oil and gas leases (in thousands)	**937**	839	766	557	421	278	206	—
Operating revenues	**$ 10.8**	$ 5.7	$ 4.3	$ 2.3	$ 1.4	$ —	$ —	$ —
Operating income	**$ 4.7**	$ 1.2	$ 1.1	$ .6	$ .6	$ —	$ —	$ —
Net exploratory wells drilled	**8.4**	8.5	8.3	3.9	4.3	1.0	8.7	—
Net development wells drilled	**6.8**	26.0	19.1	15.5	6.7	.1	1.0	—
Number of employees, end of period	**48**	44	26	21	21	—	—	—
Total assets, end of period	**$ 130**	$ 66	$ 41	$ 28	$ 20	$ 10	$ 5	$ —
Coal Statistics:								
Tons of coal sold (in thousands)	**764**	863	599	295	213	154	210	—
Operating revenues	**$ 21.6**	$ 23.6	$ 11.5	$ 5.1	$ 4.9	$ 4.9	$ 5.2	$ —
Operating income (loss)	**$ (6.5)**	$ (8.7)	$ (3.5)	$ (1.3)	$ (1.4)	$ .5	$ .3	$ —
Number of employees, end of period	**288**	312	222	150	140	88	128	—
Total assets, end of period	**$ 46**	$ 45	$ 28	$ 20	$ 17	$ 17	$ 15	$ —

*Operations commenced February 1, 1974.

Consolidated Financial Statistics

February 1, 1974 Through December 31, 1981

Northwest Energy Company and Subsidiaries

(Dollars in Millions, Except Per Share Amounts)	1981	1980	1979	1978	1977	1976	1975	1974*
Operating Revenues:								
Gas sales	**$1,256**	$1,212	$1,046	$ 776	$ 731	$ 591	$ 456	$ 266
Liquid product sales	**59**	65	46	28	29	25	21	8
Other	**37**	18	14	7	7	5	1	1
Total Pipeline revenues	**1,352**	1,295	1,106	811	767	621	478	275
Northwest Coal sales	**22**	23	12	5	5	5	5	—
Exploration Company oil and gas sales	**11**	6	4	2	1	—	—	—
Intercompany sales and other	**14**	(1)	(2)	2	—	—	—	—
Consolidated operating revenues	**$1,399**	$1,323	$1,120	$ 820	$ 773	$ 626	$ 483	$ 275
Income—								
Net income before extraordinary items	**$ 70.1**	$ 54.1	$ 41.3	$ 23.4	$ 23.4	$ 22.8	$ 22.5	$ 14.4
Extraordinary items	**—**	—	—	15.4	—	—	—	—
Net income	**70.1**	54.1	41.3	38.8	23.4	22.8	22.5	14.4
Less—Preference stock dividends	**6.3**	2.8	—	—	—	—	—	—
Net income applicable to common stock	**$ 63.8**	$ 51.3	$ 41.3	$ 38.8	$ 23.4	$ 22.8	$ 22.5	$ 14.4
Income Per Share:**								
Primary—								
Before extraordinary items	**$ 3.83**	$ 3.23	$ 3.03	$ 1.81	$ 1.82	$ 1.77	$ 2.13	$ 1.37
Extraordinary items	**—**	—	—	1.20	—	—	—	—
Total	**$ 3.83**	$ 3.23	$ 3.03	$ 3.01	$ 1.82	$ 1.77	$ 2.13	$ 1.37
Fully diluted—								
Before extraordinary items	**$ 3.64**	$ 3.16	$ 3.01	$ 1.79	$ 1.81	$ 1.76	$ 2.12	$ 1.37
Extraordinary items	**—**	—	—	1.18	—	—	—	—
Total	**$ 3.64**	$ 3.16	$ 3.01	$ 2.97	$ 1.81	$ 1.76	$ 2.12	$ 1.37
Common Stock:**								
Weighted average shares, in thousands—								
Primary	**16,882**	15,876	13,600	12,905	12,857	12,857	10,531	10,474
Fully diluted	**19,510**	17,099	13,719	13,032	12,961	12,961	10,594	10,531
Dividends declared per share	**$ 1.15**	$ .95	$ .85	$ .783	$ .717	$ .667	$ .60	$ .267
Dividends as a percent of net income	**30%**	29%	28%	43%	39%	38%	28%	19%
Annual dividend rate, end of period	**$ 1.20**	$ 1.00	$ .867	$ .80	$ .733	$ .667	$ .667	$ .533
Book value per common share	**$21.68**	$18.78	$16.37	$14.77	$12.68	$11.57	$10.56	$ 9.78
Year-end market price per share	**$ 20⅞**	$ 31⅞	$ 20⅝	$ 8⅞	$ 12¾	$ 11⅛	$ 8¼	$ 4½
Market price as a percent of book value	**96%**	170%	126%	60%	101%	96%	79%	46%
Price/earnings ratio, end of period	**5.5**	9.9	6.8	4.9	7.0	6.3	3.9	3.3
Capitalization, end of period:								
Common stockholders' equity	**$352.1**	$301.0	$257.7	$190.8	$163.0	$148.8	$135.7	$102.4
Preference stock	**71.2**	71.2	—	—	—	—	—	—
Preferred stock of Pipeline	**52.5**	53.7	55.0	55.0	20.0	20.0	—	—
Long-term debt, less current maturities	**420.5**	229.6	245.6	261.6	224.8	248.6	222.5	208.1
Total capitalization	**$896.3**	$655.5	$558.3	$507.4	$407.8	$417.4	$358.2	$310.5

*Operations commenced February 1, 1974.
**Restated, as applicable, to reflect a 100% common stock distribution on June 8, 1979 and a 50% distribution on September 12, 1980.

Northwest Energy Company

Directors

John G. McMillian
is Chairman of the Board and Chief Executive Officer of the Company. He is also Chairman, President and Chief Executive Officer of Northwest Pipeline Corporation and Chairman of the Executive Committee of the Company.

Thomas W. diZerega
is President of Northwest Energy Company and a member of the Executive Committee of the Company. He is also Vice President—Law of Northwest Pipeline Corporation.

F. Arnold Daum
is a senior partner of the New York law firm of Cahill Gordon & Reindel. He is a member of the Executive and Compensation Committees of the Company.

L. P. Himmelman
is former Chairman and Chief Executive Officer of Westin Hotels (hotel ownership and management), Seattle. He is Chairman of the Compensation Committee of the Company.

Allan D. Insley
is an independent financial consultant headquartered in Calgary, Alberta, Canada. He is a member of the Audit Committee of the Company.

S. Lee Kling
is Chairman and Chief Executive Officer of Landmark Bancshares Corporation (bank holding company), St. Louis. He is also Vice-Chairman of Reed Stenhouse, Inc. (insurance brokerage) and is a member of the Executive, Compensation and Audit Committees of the Company.

Marne Obernauer
is Chairman of Devon Group, Inc. (graphic arts, wine and spirits distribution), Stamford, Connecticut. He is a member of the Audit Committee of the Company.

George S. Patterson
is an independent petroleum consultant headquartered in New York City. He is a member of the Company's Compensation Committee.

Louis B. Perry
is President of Standard Insurance Company (life insurance), Portland, Oregon. He is Chairman of the Company's Audit Committee.

David K. Watkiss
is a senior partner in the Salt Lake City law firm of Watkiss & Campbell and is a member of the Company's Executive Committee.

Special Consultant,
Mark J. Millard,
is a Senior Managing Director, Shearson/American Express, Inc. (investment bankers), New York City. He is a special consultant to the Board of Directors of the Company.

Principal Officers

John G. McMillian
Chairman of the Board and Chief Executive Officer

Thomas W. diZerega
President

A. N. Porter
Vice President—
Chief Financial Officer

R. W. Keener
Vice President—Pipeline Operations and Gas Supply

James B. Mason
Vice President and Secretary

H. F. Assmus
Vice President and Treasurer

Gene C. Brown
Vice President—
Accounting and Taxes

John R. Grantham
Sr. Vice President—
Facilities

William D. Owens
Vice President

W. Merwyn Pittman
Vice President—
Administration

Joseph N. Vallely
Vice President—
Public Relations

Louis L. Denton
Controller—
Chief Accounting Officer

Corporate Information

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P.O. Box 1526
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Transfer Agent and Registrar
The Chase Manhattan Bank (N.A.)
One New York Plaza
New York, New York 10015

Independent Public Accountants
Arthur Andersen & Co.
36 South State Street
Salt Lake City, Utah 84111

Availability of Form 10-K
The Company's annual report to the Securities and Exchange Commission on Form 10-K, which will contain certain information not presented in this report, will be filed on or about March 31, 1982. Copies of Form 10-K may be obtained after that date without charge—and exhibits thereto at cost—upon written request to:

Stockholder Relations
Department
Northwest Energy Company
P.O. Box 1526
Salt Lake City, Utah 84110

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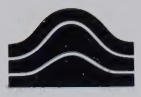

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